RIIO Transmission Annual Report 2013-14

Annual Report

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Target Audience: This document may be of particular interest to users of the transmission networks, licensees, and providers of finance and consumer groups

Overview:

RIIO-T1 is the first transmission price control, along with its equivalent gas distribution (RIIO-GD1), that utilises the RIIO (Revenue = Incentives + innovation + outputs) price control model. This price control began on 1 April 2013 and runs for eight years, to 2021.

This report reviews the progress transmission companies have made in the first year, and their forecast for the remainder of the eight year period, comparing their performance with the outputs they are committed to deliver and the costs they have incurred against allowed revenues.

In addition, the report outlines the performance of the system operator (SO) companies, whose role is to ensure that the gas and electricity system remains in balance.

Context

We regulate the monopoly and some of the competitive segments of the gas and electricity markets. The competitive segment broadly encompasses the wholesale and retail markets of electricity and gas. The networks that transport the gas and electricity from producers to consumers are largely monopoly businesses except for where competition is introduced. The regulation of the monopoly network businesses is mainly through periodical price controls. These limit the amount by which costs can rise and stipulates levels of performance, thus ensuring value for money for consumers.

The electricity transmission network consists of the high voltage electricity wires which convey electricity from power stations to local distribution networks and large customers directly connected to the transmission system. The gas transmission network consists of high-pressure long distance gas pipelines and compressors which transport gas from offshore, storage and LNG facilities to local gas distribution networks.

There are three onshore monopoly electricity transmission owners (TO) and one gas TO in Great Britain:

- National Grid Electricity Transmission plc (NGET), which owns the high voltage electricity network in England and Wales
- Scottish Hydro Electric Transmission plc (SHE Transmission), which owns the high voltage electricity network in the north of Scotland
- SP Transmission plc (SPTL), which owns the high voltage electricity network in the south of Scotland
- National Grid Gas plc (NGGT), which owns the high pressure gas transportation system across Britain.

In addition to their TO responsibilities, NGET and NGGT are the designated electricity and gas System Operators (SOs) respectively. They are responsible for day-to-day system operation, including balancing of the system and constraint management. The price controls for NGET and NGGT include allowances for the internal costs (staff and IT costs)for NGET SO and NGGT SO. All external SO cost allowances for system balancing are determined via a separate process.

In December 2012 we published our final proposals for RIIO-T1. This set out the baseline revenues the TOs and SOs could recover and the outputs they would deliver for the eight year period commencing 1 April 2013. It also contains processes to vary revenues as the needs for the transmission system develops and/or their performance exceeds or falls short of pre-set targets.

The key changes between the RIIO price control and previous price controls are as follows:

- An emphasis on outputs that companies are expected to deliver to provide a clearer link between value for consumers and costs.

- Incentives are equalised between operating costs and capital expenditure. Companies are therefore monitored on total expenditure (totex) performance.
- A longer period of eight years (rather than five) to give companies more certainty and enable them to focus more on delivering for consumers.
- The introduction of a process to feed TOs' actual performance into revenue calculations annually.

The first year of the price control ended on 31 March 2014, and this report draws upon the data and supporting information submitted by TOs and SOs. This report reviews how the companies have performed and are forecasting to perform against the outputs and allowances set. It reviews their effectiveness in delivering services cost-efficiently and the benefits they have delivered to consumers and stakeholders.

This and subsequent annual reports will build the picture of TOs' and SOs' performance over RIIO-T1. These reports will also highlight to them and other stakeholders where we will be focusing our analysis in future. This should encourage TOs and SOs to provide better explanations of performance in returns and information provided to all stakeholders.

Note

Please note that all financial figures are quoted in 2013-14 prices unless stated otherwise. This includes forecast figures.

Associated documents

Price Control Documents

RIIO-T1: Final Proposals for NGGT and NGET - Overview

RIIO-T1: Final Proposals for NGGT and NGET – Outputs, incentives and innovation

RIIO-T1: Final Proposals for NGET and NGGT – Cost assessment and uncertainty

RIIO-T1: Final Proposals for NGGT and NGET – Finance

RIIO-T1: Final proposals for SP Transmission Ltd and Scottish Hydro Electricity Transmission

Transmission networks own reports on their 2013-14 performance

RIIO-T1: performance data

NGET's 2013-14 performance report

NGGT's 2013-14 performance report

SHE Transmission's 2013-14 performance report

SPTL's 2013-14 performance report

Ofgem TPCR-4 performance report

Transmission networks: Report on the performance of Transmission Owners during he regulatory periods TPCR4 and TPCR4RO

Contents

Executive Summary

In July 2014 the Transmission Owners (TOs) submitted to Ofgem their regulatory reporting packs covering the first year of RIIO-T1 (2013-14). We have now reviewed these results and where necessary discussed them with individual companies. In RIIO the focus is on outputs, incentives and innovation as well as total expenditure (totex). Some of the required outputs will not be fully delivered until the end of RIIO-T1 (2020-21) and therefore this report considers forecast performance across the whole price control as well as in the current year.

As part of the agreed initiative to make company performance more transparent in RIIO, TOs have already published their own annual performance reports on their company websites at the end of September 2014. This report is therefore designed to give a combined picture of the results rather than re-presenting the numbers which are already in the public domain. We will also highlight to TOs and other stakeholders areas where we will be focusing our attention in future years. This hopefully will encourage TOs to address our concerns in their future returns.

2013-14 Performance Headlines

Customer Bill Impact

The electricity transmission share of an average customer’s bill between April 2013 to March 2015 increased by £0.81 from £21.78 to £22.59. This reflects the increased investment in the transmission network by all three TOs to facilitate the growth in renewable generation. The gas transmission share of an average customer’s bill decreased £2.95 from £16.63 to £13.68 over the same period. This reflects the reduced financing impact of the RIIO-T1 final proposals and lower expenditure on the gas transmission network as the immediate need to expand the network identified durig the RIIO process has further reduced. The electricity transmission element of customer bills is expected to rise further in future years reflecting the large scale investment in assets that is taking place. In terms of gas we expect the transmission expect the element of customer bills to fall in future years, reflecting the lower investment.

Output Performance

After one year’s results it is too early to say whether TOs’ expected output delivery will meet the targets set against the six output categories. Some measures such as energy not supplied and customer satisfaction are calculated each year and in year one all TOs have performed better than target. In other areas such as business carbon footprint (BCF), stakeholder engagement, and the environment discretionary reward, performance has improved but not yet reached the level expected. Where targets have not been met, we expect TOs to improve their performance.

For electricity TOs the future volume of connections activity is not totally certain and we have therefore assumed a baseline level of generation connection will be delivered. There are mechanisms in place so that the allowed funding will be recalculated depending on connections outputs delivered. Larger investment schemes are dealt with under the strategic wider works (SWW) process and we have already agreed three such projects for SHE Transmission under SWW. Other schemes are in the planning stage and we have recently received an application from NGET regarding reinforcement in the Hinkley-Seabank area.

All TOs made use of their network innovation allowance to develop ideas and projects that may bring benefits in the future.

We note progress in a number of areas, but more work is required to ensure that all outputs will be delivered. We will be working with the TOs to improve reporting and understanding of asset health and network output measures (NOMs) which were included to ensure we had leading indicators of network performance in place for RIIO.

Financial performance

The financial performance of transmission companies is presented using the return on regulatory equity (RoRE) measure. Based on the latest forecasts from the TOs, all of them expect to exceed the expected return allowed in the RIIO-T1 Final Proposals, by between 0.4% and 1.6%. The allowed return for electricity TOs was 7% and for gas 6.8%. The forecast RoRE is dependent on future delivery of outputs, which is not confirmed at this stage, and so this should be seen as the best estimate that is available.

The regulatory asset values (RAV) of the electricity TOs are expected to grow significantly over the RIIO-T1 period reflecting the investment necessary to remodel the system to cope with the impacts of new generation.

Totex performance

In 2013-14 all TOs have spent less than their allowance mainly as a result of lower load related (new connections activity) capex due to changes and delays in demand. For electricity TOs, if the baseline connections outputs are not achieved, the level of allowances will be scaled back by the mechanisms in place to reflect volume uncertainty. NGGT underspent its load-related allowance by 98% reflecting the current lack of new connections activity for gas transmission. In the future all TOs are expecting outperform the efficiency targets used in setting allowances for RIIO-T1 and a share of these efficiencies (savings) will be shared with consumers.

We expect TOs to make savings against the price control allowances. Despite making forecasting savings against allowances TOs say that they will meet output targets.. Having analysed TOs' submissions for 2013-14 we are concerned that some of these projected underspends may impact on output delivery such as NOMs performance and we will monitor this closely over the RIIO-T1 period. In particular we need to consider further the changes in NGGT's latest RIIO-GT1 forecast and the drivers for these changes. There are a number of projects NGGT identified in the development of its RIIO-T1 plan which have been funded which NGGT are stating are no longer needed. We need to understand further the new information received by NGGT to inform this decision.

Quality of regulatory reporting submissions

Every year we require all TOs to provide us with financial data and information that is of good quality and consistent with other information they put into the public domain. This year we have had to ask NGET and NGGT to resubmit some of their regulatory reporting packs due to the poor quality of the original submissions. NGET and NGGT have confirmed they are taking steps to improve their reporting for the ongoing period and we will consider whether any further regulatory action is necessary if we do not see the expected improvements..

Having reviewed the reporting from the TOs in 2013-14 we have also identified scope for improvements in reporting. These developments should help us to better understand and critically review TOs’ performance during RIIO-T1 and improve the information within the annual report.

1. Revenue and Customer Bill Impact

Chapter Summary

This chapter explains how expenditure made by the Transmission Operators to improve the UK's transmission infrastructure in RIIO-T1 impacts on customer electricity and gas bills.

Analysis of Transmission Revenue

Background

1.1. In TPCR4 the electricity and gas transmission licensees spent £11bn over a six-year period on the transmission network in order to move to a more carbon neutral energy system and maintain safety, security and affordability for existing and future consumers.

1.2. Out of this £11bn, £9bn was invested in new electricity and gas transmission assets with the remainder being spent on network maintenance and other related activities.

Electricity

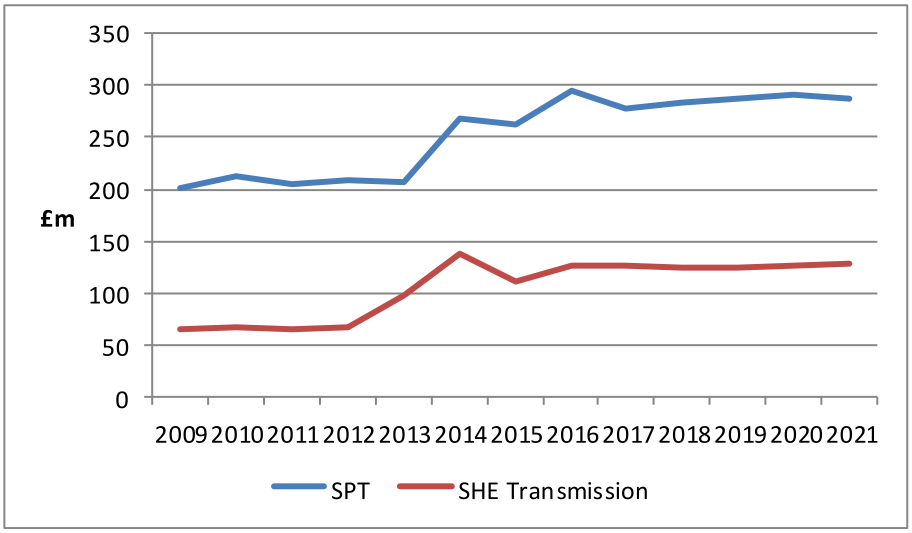
1.3. Over RIIO-T1, the transmission licensees expect to spend c. £17bn[1] developing smarter transmission networks, connecting new sources of renewable generation and improving environmental performance. This will contribute to a higher allowed revenue profile for the licensees between 2013-14 and 2020-21 (see Figure 1 and 2 below) and consequently an increase in electricity network charges as explained below.

1.4. In the first year of RIIO-T1, total allowed revenues have increased £73m (3.7%) compared to the final year of TPCR4. This is consistent with higher additions to the regulated asset base in 2013-14 compared to 2012-13 which has caused base revenues to increase.

1.5. There is a minor decrease in revenue from incentives in 2013-14 due to the two-year lag in the recognition of actual incentive performance (compared to TPCR4 incentives which were mostly settled in 2012-13).

[1] This represents 2013-14 actual totex plus seven years forecasted spend for 2014-15 to 2020-21 based upon the TOs' latest published figures.

Figure 1: Base revenue[2] (£m) profiles for SHE Transmission and SPTL

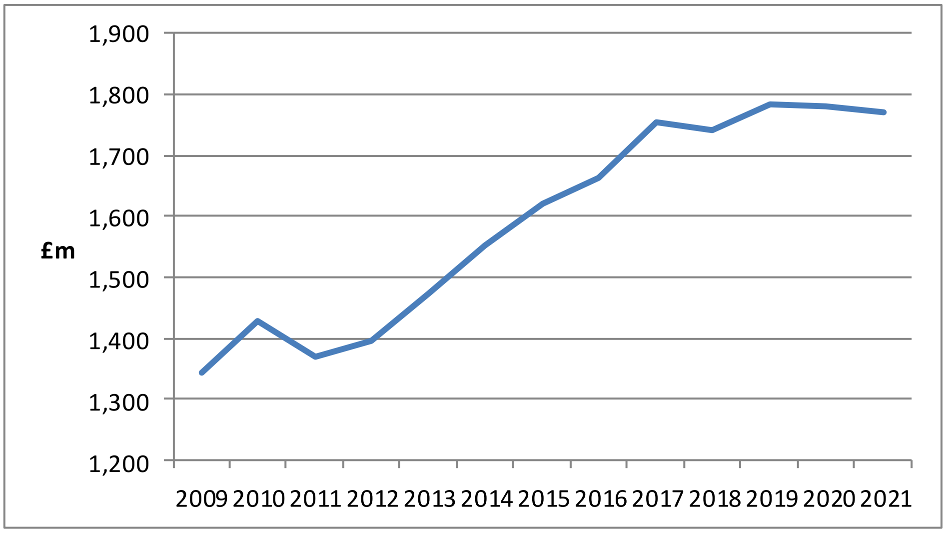


1.6. The increase in SHE Transmission's forecast base revenue over the first three years of RIIO-T1 is driven by large new infrastructure projects (eg Beauly Denny) being undertaken. This reflects the major growth in the North of Scotland network that is required to connect new forms of generation (predominantly windfarms). Over the RIIO-T1 period the Regulatory Asset Value for SHE Transmission is expected to triple in size (see chapter 4).

1.7. SPTL's eight-year base revenue forecast reflects a steady increase in expenditure over RIIO-T1 as new renewable generation is connected to the transmission network (with an accompanying increase in shared infrastructure assets), and strategic wider works projects to upgrade the network as a result of increased renewable generation.

[2]Base revenue figures for 2008-9 to 2012-13 are derived from SHE Transmission and SPTL's submitted Revenue RRPs. Base revenues for 2013-14 to 2020-21 are derived from the PCFM published as part of the November 2014 Annual Iteration Process. The impact of 2013-14 actual totex performance is reflected in the 2015-16 MOD adjustment to base revenue. The networks' published totex forecasts for 2014-15 to 2020-21 are not incorporated in the base revenue forecasts for the equivalent years.

Figure 2: Base revenue[3] (£m) profile for National Grid Electricity Transmission (TO)



1.8. NGET has stated that the outputs included in its Final Proposals baseline (based upon the 'Gone Green scenario') are no longer representative of what has actually transpired in 2013-14 due to the state of the UK economy and other factors. As a result generation, demand and incremental wider works outputs are expected to be significantly below baseline. Around 21GW less generation is currently anticipated to connect over RIIO-T1 and as a result of lower demand around 20 fewer super-grid transformers (SGTs) are required to facilitate connections over the same period.

1.9. At the end of 2013-14 there has been underspend on both load and non-load related capex. Uncertainty mechanisms are in place within RIIO-T1 to adjust the level of funding over the eight year price control period based upon variations in stakeholder needs.

Gas

1.10. Over RIIO-T1, NGGT has forecast that c. £2bn[4] of expenditure will be required to connect incremental capacity, improve network flexibility, meet emission targets

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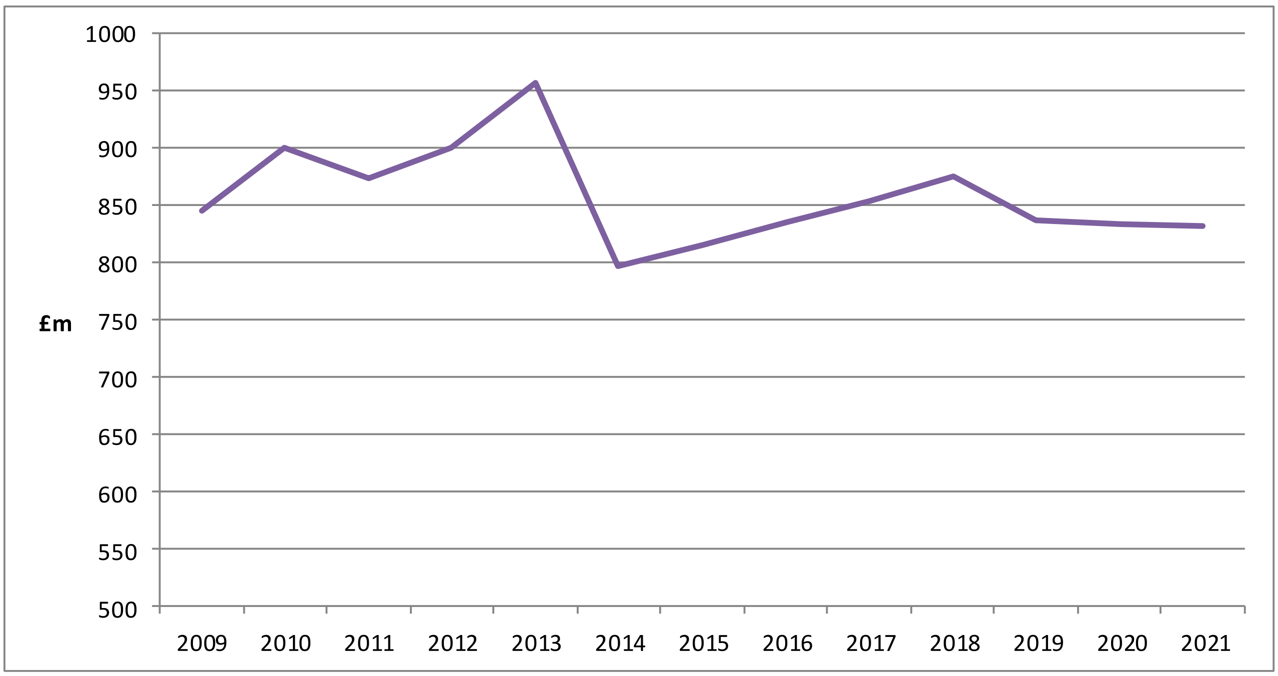
[3] Base revenue figures for 2008-9 to 2012-13 are derived from NGET's submitted Revenue RRPs. Base revenues for 2013-14 to 2020-21 are derived from the PCFM published as part of the November 2014 Annual Iteration Process. The impact of 2013-14 actual totex performance is reflected in the 2015-16 MOD adjustment to base revenue. NGET's published totex forecasts and forecast allowances for 2014-15 to 2020-21 are not incorporated in the base revenue forecasts for the equivalent years.

[4] This represents 2013-14 actual totex plus seven years forecasted spend for 2014-15 to 2020-21 based upon the TOs' latest published figures.

and maintain asset health. Overall it was expected that total allowed revenues for NGGT will be higher in RIIO-T1 compared to TPCR4 (see Figure 5 below).

1.11. In the first year of RIIO-T1, total allowed revenues have decreased £179m compared to the final year of TPCR4, which has resulted in a fall in gas network charges as explained above. This decrease reflects phasing in load-related investment in capacity to future years and a focus on non load-related expenditure on asset health in the first few years of RIIO-T1. Phased load-related investment on Scottish '1 in 20' projects and the Avonmouth LNG replacement solution is expected to contribute to higher revenue allowances in the later years of RIIO-T1.

Figure 3: Base revenue[5] (£m) profile for National Grid Gas Transmission (TO & SO)



1.12. In order to fully understand how NGGT's base revenue will impact annual consumer bills over the eight year price control period both the TO and SO elements of base revenue need to be considered. NGGT's combined base revenue is forecast to decline between 2013-14 and 2020-21 with shift in revenue from the SO to TO between 2017-18 and 2020-21. This reflects the end of legacy SO revenue driver allowances from TPCR-4 (which will decline from £94m in 2013-14 to £0m in 2017-

[5] Base revenue figures for 2008-9 to 2012-13 are derived from NGGT's submitted Revenue RRPs. Base revenues for 2013-14 to 2020-21 are derived from the PCFM published as part of the November 2014 Annual Iteration Process. The impact of 2013-14 actual totex performance is reflected in the 2015-16 MOD adjustment to base revenue. NGGT's published totex forecasts and forecast allowances for 2014-15 to 2020-21 are not incorporated in the base revenue forecasts for the equivalent years.

18), with a corresponding increase in the TO base revenue allowances from 2017-18 onwards.

1.13. NGGT has highlighted in its 2013-14 regulatory reporting submissions that a number of external economic and political factors are influencing the business case for development of gas projects in the UK, resulting in a challenging investment environment for new gas-fired generation and storage. As a result of this and other factors NGGT expects limited load-related investment on the National Transmission System (NTS).

1.14. At the end of 2013-14 there has been underspend on both load- and non load-related capex, which is expected to create a lower allowed revenue profile over RIIO-T1 than expected at Final Proposals.

Customer Bill Impact

1.15. Consumers pay licensed Transmission Operators (TOs) to operate and maintain the transmission networks through their annual gas and electricity bills. Transmission network charges accounted for approximately 4% of the average annual customer electricity bill and 2% of the average annual customer gas bill at the beginning of RIIO-T1 (1 April 2013)[6].

1.16. In 2013-14 the average electricity transmission charge increased by £0.81 from £21.78[7] to £22.59 and the average gas transmission charge decreased by £2.95 from £16.63 to £13.68. A breakdown of the transmission charge movements in the average annual electricity and gas bills is shown in figures 4 and 5 below:

[6] The % shares of the average annual customer gas and electricity bills attributable to transmission network charges are estimated from October 2014 Supplier Market Indicator data collected by Ofgem.
[7] The average transmission network charges per household at the end of TPCR4, which was the price control in place between 2007-08 and 2012-13, were £21.24 and £16.22 for gas and electricity respectively. The opening positions for RIIO-T1 have been re-based from 2012-13 to 2013-14 prices for the purposes of the bill impact analysis.

Figure 4: £ impact of RIIO-T1 on the average annual household electricity bill (2013-14 from 2012-13)

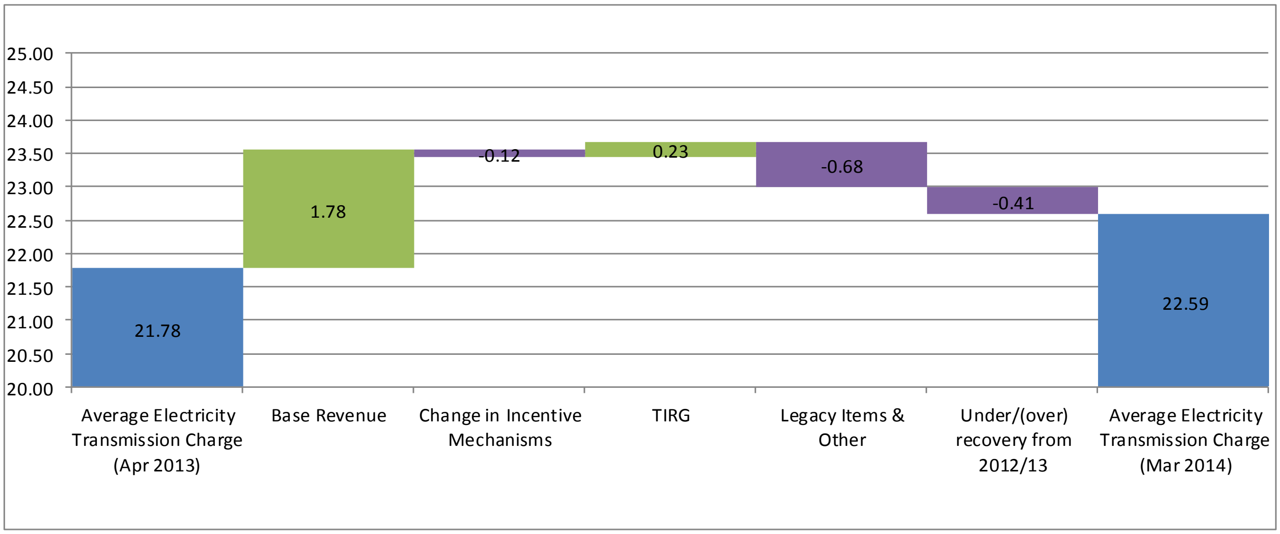
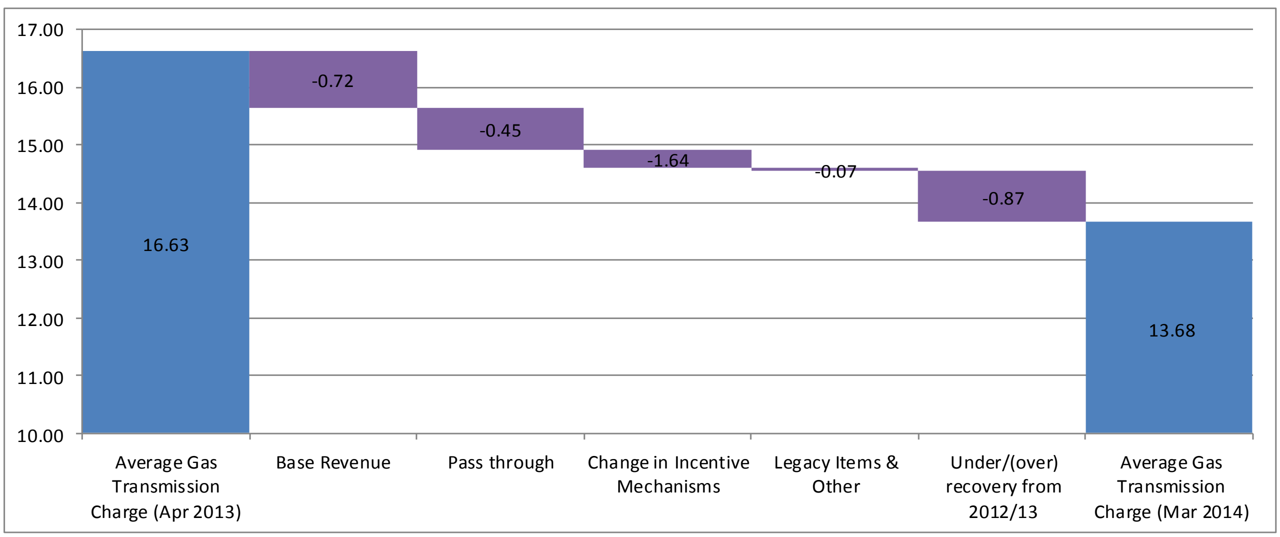


Figure 5: £ impact of RIIO-T1 on the average annual household gas bill (2013-14 from 2012-13)



1.17. The annual bill impact is driven primarily by changes in the levels of investment and returns set for RIIO-T1, which impacts the allowed revenue that can be earned by the TOs and subsequently the transmission network charges passed onto the consumer. Our methodology to calculate the annual bill impact is set out in Appendix 2.

1.18. The agreed level of investment was set by the Authority for the eight-year price control period (2013-14 to 2020-21) at RIIO-T1 Final Proposals. The increase in electricity allowed revenues between 2013-14 vs. 2012-13 relates to:

- **Base Revenue**: The allowed return (set by the Authority) that licensees can earn from operating regulated transmission assets and making efficient investments in new transmission infrastructure. Base revenue is the most significant determinant of network charges levied by the licensees on customers and is annually updated for actual outputs delivered and cost performance.

- **Pass through**: Costs that we agree are outside of the licensees' complete control and are therefore allowed to be passed on in full to the customer e.g. licence fees, business rates.

- **Change in incentive mechanisms**: In RIIO-T1 TOs will receive payments (two years in arrears) under various incentive schemes relating to safety, wider works, reliability, connections, customer service, social obligations and environment where they have delivered outputs above the assumed level. The impact on annual bills reflects this delayed timing.

- **Transmission Investment in Renewable Generation (TIRG)**: TIRG was introduced in 2004 as a mechanism to fund projects that connect renewable generation to the electricity transmission network. To minimise delays in funding TIRG sits outside base revenue until projects have reached completion and then transfer to the main regulated asset base.

- **Legacy items and other**: Legacy items relate to revenue from mechanisms and incentives that were part of the previous price control and that have been recognised in 2013-14. These items reflect adjustments to TPCR4 expenditures. This category also includes other items which are not recoverable through base revenue.

- **Under-/over-recovery from 2012-13**: Relates to the difference between 2012-13 actual revenue and 2012-13 allowed revenue, which is corrected for in 2013-14.

1.19. The key driver of change in the annual electricity bill is the increased investment in assets such as new lines. For example major investment is being carried out on schemes such as the Western HVDC (£240m this year), Beauly to Denny (£200m) and Kintyre to Hunterston (£27m).

1.20. For gas transmission, the reduction in the annual bill reflects lower allowed returns, a lower investment in new assets, and less incentive payments than in the prior year (which included settlement of some incentives relating to the whole TPCR4 period).

2. Outputs

Chapter Summary

This chapter examines the first year performance and forecast performance of the TOs in meeting their output commitments and incentive targets over the RIIO-T1 period.

Overall output targets and performance

2.1. As part of RIIO-T1, we set outputs the TOs have committed to deliver over the price control period. The following six outputs form the cornerstone of the new RIIO price control framework[8]:

- safety
- reliability
- availability
- customer satisfaction
- connections
- environmental

2.2. In most cases it is impossible to measure the outputs with a single metric. Therefore we identified a number of outputs or measures which we consider are measurable, as shown in the table below. If TOs achieve the measures satisfactorily we consider that they will have achieved the primary outputs. After one year results it is difficult and potentially misleading to draw any firm conclusions from the TOs' performance.

2.3. This chapter considers delivery by the electricity TOs then delivery by NGGT TO.

[8] Further detail of the outputs framework in RIIO-T1 is available on the Ofgem website in the link RIIO-T1: Final Proposals for NGGT and NGET – Outputs, incentives and innovation

Electricity outputs, measures and incentives performance

Table 1: Electricity outputs and measures

Primary Output	Measures
Safety	Network Output Measures (NOMs)
Reliability	Energy not Supplied (ENS)
	NOMs
Availability	Network Access Policy
Customer Satisfaction	Customer Satisfaction Survey, Stakeholder engagement discretionary reward
Connections	Baseline and Strategic Wide Works Connections
	Generation connections
	Local Demand connections
	NGET planning requirements
Environmental	SF6
	Business Carbon Footprint
	Losses
	Environmental Discretionary Reward

2.4. Outputs that are directly linked with network capex (NOMs and connections) are discussed in Chapter 4.

Reliability

Energy not supplied (ENS)

2.5. All three Electricity Transmission Owners (ETOs) outperformed against their targets in 2014 as shown in table 2 below.

Table 2: ENS performance in 2013-14

			2014		
		Units	NGET	SHE_T	SPT
Energy not supplied (Incidents)	Number of transmission system incidents	#	9	20	17
	Number of excluded incidents (other than exceptional events)*	#	2	17	10
	Number of transmission system incidents categorised as 'exceptional events'	#	-	-	1
	Number of transmission system incidents due to Incentivised Loss of Supply Events	#	**7**	**3**	**6**
Energy not supplied (Volumes)	Volume of unsupplied energy	MWh	135.9	79.8	42.4
	Volume of unsupplied energy from excluded incidents (other than exceptional events)*	MWh	0.9	44.2	0.1
	Volume of unsupplied energy in incidents categorised as 'exceptional events'	MWh	-	-	0.1
	Volume of unsupplied energy in incidents due to Incentivised Loss of Supply Events	MWh	**135.0**	**35.6**	**42.2**
Energy not supplied (Targets)	Output target volume (fixed for RIIO-T1)	MWh	316.0	120.0	225.0
	Difference (negative indicates outperformance of targets)	MWh	**-181.0**	**-84.4**	**-182.8**

* Events of the type specified to be excluded from the definition of 'Incentivised Loss of Supply Event' under the transmission licence Special Condition 3C

Availability

Network Access Policy (NAP)

2.6. The output was to develop a NAP within a month of the start of RIIO-T1, and use this as a live document. The NAP was required to be reviewed regularly and potentially updated. All three TOs have developed a NAP and are operating consistently with these. Regular meetings demonstrate continued communication on how to preserve and enhance the benefits of effective SO:TO interaction identified in developing the NAP.

Customer Satisfaction

Customer/stakeholder satisfaction survey

National Grid Electricity

2.7. NGET uses customer & stakeholder satisfaction surveys combined as a measure of its performance. The raw results that inform the financial incentive in this area are focused on the same overarching question rating satisfaction on a scale from 1 – 10, one for customer and the other for stakeholder survey.

2.8. NGET had developed a customer satisfaction survey during the previous control period. This gave us confidence in the baseline set to apply throughout the RIIO-T1 period of 6.9. A cap and collar are applied to ensure the financial incentives are not distorted by outlier figures.

2.9. While the survey considers the different transmission activities, the question that feeds into the financial incentive is an overarching question on overall satisfaction with NGET. This is scored on a 0 to 10 scale with the baseline set at 6.9. NGET scored 7.4 against the baseline Each year provides more information on the way stakeholders respond to surveys that will help with the design of future incentives in this area.

SP Transmission and SHE Transmission

2.10. The two Scottish TOs record performance against a stakeholder satisfaction survey and against a set of key performance indicators (recognising that as above for NGET we have very limited evidence as to how stakeholders respond to surveys). The survey performance is also driven by an overarching question on a 0 – 10 scale. In the absence of evidence, we set the baseline or bar at 5. Table 3 summarises their performance.

Table 3: Scottish TOs stakeholder satisfaction results

Company	Survey (0-10, baseline 5)	KPI (0-100, baseline 50)
SP Transmission	7.4	72.1
SHE Transmission	6.5	91

2.11. These key performance indicators (KPIs) are measures that each of SPT and SHE Transmission developed to cover their respective connections activities, working with the system operator and where the quality of delivery of these is not otherwise assessed ie by other output measures. This supports the stakeholder survey where there remains significant uncertainty about how stakeholders (without contractual links) might mark the survey.

2.12. There remains uncertainty in how stakeholders respond to a survey and in the early years around performance against the KPIs. This is the reason we set conservative baseline levels. We will review this further for future years of the control. Despite this uncertainty and any future changes, we see the above scores as reflecting strong performance by both companies.

Stakeholder engagement discretionary reward

2.13. All three electricity TOs made submissions to our stakeholder engagement discretionary reward. This provides financial reward where effective stakeholder engagement results in high quality outcomes. This is designed to lock in the improvements we saw in the RIIO-T1 price control in the way the TOs worked with their stakeholders to understand their needs and increase general understanding of priorities.

2.14. Compared to distribution companies, transmission companies have to make more progress, since in general they collectively scored lower. The results of this year's assessment, while improving over the 'dry run' in the year before RIIO-T1 was introduced, still leave room for improvement. This is understandable given the more established direct relationship between distribution network companies and customers. More detail is in our report on this year's stakeholder engagement discretionary reward[9].

Table 4 Stakeholder engagement discretionary rewards scores

Company	Score (out of 10)
NGET	5.75
SHE Transmission	5.4
SP Transmission	4.9

Connections

Wider works outputs

2.15. To connect new generation, maintain security of supply and bring low carbon benefits, we have been managing programmes which fund the TOs for transmission network reinforcement. Two major investments projects funded prior to RIIO-T1 are due to complete by 2017.

[9] See https://www.ofgem.gov.uk/ofgem-publications/91799/reporttosstakeholderengagementscheme2014.pdf

Baseline wider works outputs

- Beauly-Denny: this upgrades the existing 132kV transmission line to 400kV between Beauly in the north of Scotland and Denny in central Scotland. This will help to reduce constraints and losses on the network, and facilitate the connection of additional renewable generation. The majority of the northern section of the project has now been energised, with the southern section expected to be completed between November 2015 and summer 2016. In November 2014 we approved a request for additional funding and an extended construction period for the project by SPTL for the forecast cost increase and delays in its section.
- Western HVDC link: this is a new sub-sea link between Scotland and England with a capacity of 2,400MW and will help reduce constraints between Scotland and England. Delivery was expected to be completed in summer 2017, but this is now unlikely due to technical difficulties and the final date is subject to review. The funding for this project was approved in 2012.

Strategic wider works outputs

2.16. RIIO-T1 put in place the Strategic Wider Works (SWW) process for the approval of future major investments. In their RIIO-T1 business plans, the three onshore TOs identified transmission projects totalling approximately £9 billion that may be needed over the next decade.

2.17. To date, we have received three proposals for new transmission projects in northern Scotland from SHE Transmission with a combined total value of around £1.5 billion for assessment under SWW. In 2013-14 we approved two of these projects: Kintyre-Hunterston and Beauly-Mossford. The first project is designed to deliver 270MW of additional transmission capacity from late 2015-16, reducing existing constraints and enabling new connections in Kintyre. The second project, Beauly-Mossford, will provide 252MW of additional transmission capacity in 2015-16 north-west of Inverness. In December 2014 we also approved the third project, Caithness-Moray. This will deliver an additional 795MW of transmission capacity across the transmission system boundary B0, and 850MW across boundary B1. The additional capacity is needed by 2018 to allow around 1.2GW of renewable generation to connect.

General connection activity

2.18. We hold all transmission owners accountable for delivering timely and effective connections to the network through their licences[10]. SP Transmission and SHE Transmission also face a timely connections financial incentive where their revenues are reduced if they fail to deliver an offer of terms within the specified period.

2.19. SHE Transmission completed all 47 of its offers within this time. This covered a number of different types of connection including tidal and CHP, though most were

[10] NGET has no financial incentive but needs to comply with its licence condition obligations.

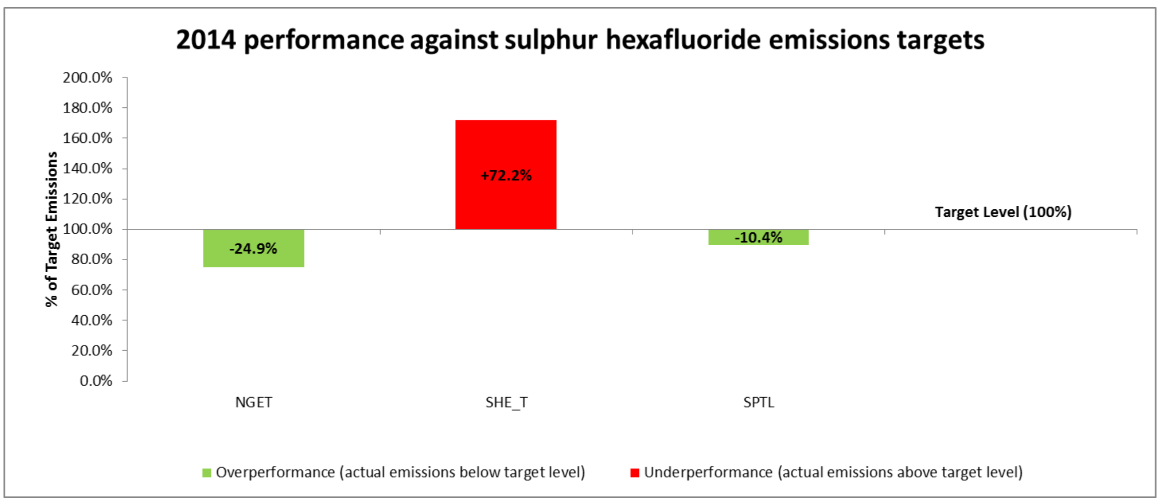
onshore wind. SPTL failed, on two of its 50 offers (one onshore wind, the other biomass), to meet the 3 month timescale as set out in its licence. We have discussed this with SPTL and this seems to be a transitional problem that has now been resolved. We will continue to keep monitoring progress.

Environmental

Sulphur hexafluoride (SF_6)

2.20. Both NGET and SPTL outperformed against target emissions levels of this greenhouse gas. A single leakage incident at SHE Transmission's Fort Augustus substation caused by a rupture disc failure on a newly commissioned 275 kV circuit breaker resulted in the loss of 113 kg of SF_6. This incident meant that SHE Transmission exceeded its target emissions level by 72% and will therefore be penalised under the SF_6 incentive mechanism. Had the Fort Augustus incident been avoided then SHE Transmission would have slightly outperformed its target.

Figure 6: SF_6 Performance 2013-14



Business carbon footprint (BCF) all TOs

2.21. Companies must report annually on the transmission network BCF. The network BCF includes:

- Scope 1 emissions directly related to the day-to-day business activities of network business.
- Scope 2 emissions which arise from operating the network, including the CO_2 emissions from losses of electricity or shrinkage of gas that occur as a result of transporting energy on the network.
- Scope 3 emissions which are due to third party contractors carrying out business activities on behalf of the network.

2.22. In 2013-14 the four transmission companies all reported to us a BCF in terms of tonnes of carbon dioxide equivalent as follows:

Table 5: BCF in terms of tonnes of carbon dioxide equivalent per licensee[11]

	SHE	SPT	NGET	NGGT
Total	183,676	237,596	2,233,421	350,192

2.23. We have also reviewed the information publicly provided by the companies to stakeholders on company BCF. We think there are some problems with the information provided, and suggest some improvements are made in the information published next year. For example:

- More information is needed to put company-specific carbon emission targets in context – a target of an X% reduction is not particularly meaningful if emissions in the base year are not referenced and there is no definition on the scope of emissions that are included in the target measure.
- Only SHE Transmission provided a complete breakdown of its BCF by category . We think that the information on network BCF would be more useful if all the companies provided a full breakdown of total emissions by source, and relative to the target the companies have set.

Losses

2.24. All TOs have a reputational incentive in relation to their overall approach to contribution to fewer transmission losses where they can do do so and provide long term value to consumers. To date all three TOs have complied with the license condition, all transmission companies have strategies in place to reduce losses on their networks and report against these annually[12].

[11] The figures for SHE Transmission and SPT represent revised submissions following the correction of significant anomalies in their original figures. We note that SPTL does not provide an estimate for the amount of emissions that are attributable to its own use of electricity at substations on its network. While this would not increase the revised BCF total above, we think it is undesirable that substation energy use (a Scope 1 emission) is not monitored and measured as this is the first step required to look for mitigation opportunities. We think there is an urgent need for both companies to review BCF monitoring and calculation processes to ensure these are fit for purpose.

[12] Losses Reports
NGET - http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=36719
SHE Transmission - https://www.ssepd.co.uk/WorkArea/DownloadAsset.aspx?id=3939
SPT - http://www.spenergynetworks.co.uk/userfiles/file/SPT%20Losses%20Report%20%202014.pdf

Environmental discretionary reward

2.25. The Environmental Discretionary Reward (EDR) is a reputational and financial incentive for electricity transmission licensees. The aims of the scheme are to encourage the companies to contribute to the transition to a low carbon energy system and to achieve high standards of environmental management. The scheme covers activities in the following categories:

- Strategic understanding and commitment to low carbon objectives
- Whole electricity system planning
- Connections for low-carbon generators
- Collaboration on innovation
- Network development solutions that avoid the need to reinforce the network
- Direct environmental impact
- Business greenhouse gas emissions

2.26. All three electricity TOs applied to the voluntary scheme in 2013-14, which is the first year it has been run following a trial in 2013. A company must provide evidence of its activity in each category to show how it has met the required criteria. We score the evidence and assign a company to a performance band ('engaged', 'proactive', or 'leadership'). Only companies that achieve a "leadership" score can get a financial reward. We indicate in the scheme guidance that to achieve leadership performance, a company must show evidence of how it is looking beyond business as usual, takes a whole system perspective, and collaborates with a range of stakeholders to achieve outstanding performance across the scheme categories. We hope to see all three companies achieve this overall level of performance in future years.

2.27. Although in all cases the underlying scores were higher than in the trial held last year, none of the companies accomplished a leadership performance band overall (see table below).

Table 6: EDR performance in 2013-14

Company	Performance band	Financial reward
NGET	Proactive	No
SHE Transmission	Engaged	No
SPTL	Proactive	No

Gas outputs, measures and incentives performance

Table 7: Gas secondary outputs and measures

Primary Output	Measures
Safety	Network output measures (NOMs)
Reliability	System reliability
	Additional capacity
	Constraint management
Availability	Baseline capacity for each entry and exit point (as set out in the licence)
Customer Satisfaction	Customer satisfaction survey, stakeholder engagement discretionary reward
Connections	Connections process established through UNC373
Environmental	Business carbon footprint

Note: Outputs that are directly linked with network capex (NOMs and connections) are discussed in Chapter 3.

Reliability

System Reliability

2.28. While there is no specific target, we expect NGGT to meet its 1:20 obligations. This means that a 1 in 20 highest winter peak demand for gas can be delivered. Our understanding of the lasting quality of the network reliability is provided by our NOMs.

Additional capacity

2.29. Only a small amount of additional capacity was delivered during the period. This was triggered during the previous price control (TPCR4 and TPCR4 roll over). No new triggers for extra network capacity at entry points were received during the first year of RIIO-T1. At exit, a small demand was met entirely through the process of substitution where capacity at a neighbouring point can be used.

Constraint management

2.30. The gas constraint management incentive on NGGT encourages the company to be efficient in managing buyback costs (costs through retrieving capacity previously sold to shippers) net of related revenues eg from gas shippers who use more than the gas they contracted for. While significant buyback activity can be very costly, NGGT's performance in 2013-14 follows recent years where the net costs were relatively small.

Availability

2.31. NGGT is meeting the availability targets. These are set as baseline capacity for each entry and exit point within its transmission licence.

Customer satisfaction

2.32. Like NGET, NGGT performed well against both customer and stakeholder surveys. The margin over expectation on the customer satisfaction was limited but reflected an improvement on previous survey results experienced by NGGT[13]. Its stakeholder survey score was 8 out of 10. At present as with electricity 90% of the financial incentive will be determined by the customer satisfaction survey while confidence in the use of surveys of stakeholders grow.

2.33. NGGT also made submission for our stakeholder engagement discretionary reward. This provides financial reward where high quality outcomes result from effective stakeholder engagement. This is designed to lock in the improvements we saw in the RIIO-T1 price control in the way the TOs worked with their stakeholders to understand their needs and increase general understanding of priorities.

2.34. NGGT scored 5.75 out of 10. As with NGET, this was the strongest TO performance. However, this still tended to trail most of the distribution companies by some distance. It is possible that NGGT like the other TOs can make enough progress next year to achieve equivalent performance with some of the distribution

[13] National Grid carried out customer satisfaction surveys for several years before we set this as part of the RIIO-T1 output incentive measures.

companies. There is more detail in our report on this year's stakeholder engagement discretionary reward[14].

Connections

2.35. There are no specific incentive measures in place for NGGT's connections performance. The output that it needs to meet is the process established under Uniform Network Code (UNC) 373 Governance of NTS connection processes, which sets out what customers can expect from NGGT in delivery of connections.

2.36. NGGT is required under UNC 373 to publish on a quarterly basis: the number of application forms submitted; and the number of full and initial connections offers made by NGGT. We understand that NGGT has complied with the required arrangements and we are not aware of any concerns.

Environmental

Business Carbon Footprint (BCF)

2.37. See BCF performance details under electricity paragraph 2.21 above

[14] See https://www.ofgem.gov.uk/ofgem-publications/91799/reporttosstakeholderengagementscheme2014.pdf

3. Innovation

Chapter Summary

This chapter presents an overview of TO's expenditure in relation to the various innovation incentives in RIIO-T1

Network innovation allowance

3.1. The Network Innovation Allowance (NIA) was established as part of the RIIO-T1 price control. The NIA provides each licensee with a set 'use it or lose it' allowance to spend on innovation projects in line with the NIA Governance Document[15] [16]. The table below shows each licensee's NIA percentage.

Table 8: Licensees Network Innovation Allowance for RIIO-T1

Licensee	NIA Percentage of Annual Base Revenue
National Grid Electricity Transmission plc	0.7
SHE Transmission plc	0.7
SP Transmission plc	0.5
National Grid Gas plc	0.7

3.2. In the first year of RIIO-T1 all licensees have implemented NIA projects. Projects have been started which if successful should: reduce safety risks, improve reliability, reduce the environmental impacts of the network, facilitate new connections, develop new commercial frameworks, strategically develop licensees' networks, improve system operability and enhance working processes.

3.3. Licensees have registered a number of projects so far: these include developing new insulated cross arms on overhead lines and researching new ways of protecting gas pipes travelling below roadways. While a project can be registered in one year the expenditure can continue over a number of years. National Grid Gas plc has registered projects with a value of £9.8m and it has spent £3m. Electricity transmission licensees have registered projects with a value of £76.1m and collectively they have spent £8.4m. All licensees spent in line with the amount that was available to them in 2013-14.

3.4. Licensees have begun to develop useful learning from this investment. Details on all projects can be found on the Energy Network Association's (ENA's) Smarter Networks Portal[17].While we are pleased that the NIA is working well and developing

[15] The Gas Network Innovation Allowance Governance Document can be found here
[16]The Electricity Network Innovation Allowance Governance Document can be found here.

[17] http://www.smarternetworks.org/

new learning we need to ensure this is shared effectively. We recently published an open letter encouraging them to improve the quality of project reporting on the Smarter Networks Portal. We encourage all licensees to consider how this can be improved. While we are concerned regarding the standard of project reporting we were generally pleased with the Annual Summary of NIA Activity published by licensees[18].

Network innovation competition

3.5. Ofgem runs two annual competitions to which transmission companies can apply: the Network Innovation Competitions (NIC) for Electricity and one for Gas. The competitions help to encourage Network Licensees (distribution and transmission) to innovate in the design, build, development and operation of their networks.

3.6. The NIC provides funding to a small number of large-scale innovation projects. Trials financed through the NIC will generate learning for all Network Licensees and will be made available to all interested parties. This learning brings potential benefits and cost savings for current and future consumers. In 2013, the first year of the NIC, two electricity transmission projects were selected and funded a total of £17.8 million. This funding is being recovered across all electricity customers during 2014-15.

Table 9 – Transmission projects selected for funding in the 2013 NIC[19]

Project Title	Lead company	Brief explanation	Funding request	Timescale
Visualisation of Real Time System Dynamics using Enhanced Monitoring (Anglo-Scottish Border)	SP Transmission plc	This project would use new sources of data and methods of analysis to optimise use of capacity on the Anglo-Scottish interconnector.	£6.5m	December 2013 to March 2017
Multi-Terminal Test Environment for high voltage direct current (HVDC) Systems (Scottish Hydro Electric Transmission Licence Area)	Scottish Hydro Electric plc	This project would establish a collaborative test and development facility for HVDC systems.	£11.3m	January 2014 to March 2021

[18] http://www.smarternetworks.org/Project.aspx?ProjectID=738#downloads
[19] More detail on the NICs and the progress of the projects can be found here: https://www.ofgem.gov.uk/network-regulation-%E2%80%93-riio-model/network-innovation

4. Costs

Chapter Summary

This chapter evaluates RIIO-T1 actual and forecast expenditure against the costs allowed in the RIIO-T1 settlement, taking into account actual and forecast workloads. It looks at the various cost categories and activities which make up total expenditure (totex). It also explains how we incorporate uncertain costs.

Note: The RIIO-T1 final proposals included a number of uncertainty and incentive mechanisms that allow the TOs to claim additional allowances if they are required to do work over and above the base allowances. Conversely, if they deliver fewer new connection outputs than assumed in the baseline then the allowances are reduced. We and the TOs have adjusted the allowances based on current estimates of what might happen in the future years of RIIO-T1.

Total expenditure (Totex) performance and forecasts

4.1. As part of RIIO-T1 we set a total expenditure allowance (totex) to enable companies to deliver their outputs. Companies are incentivised to outperform their totex allowance as part of the totex incentive mechanism (TIM). Any outperformance is shared with the customer. For RIIO-T1 around 50 per cent is retained by the company and 50 per cent of any out performance is returned to customers through revenue charges. Any underperformance (over-spend) against their allowed totex is similarly shared with the customer.

4.2. The companies reported annual totex is used to determine future revenue with any out/underperformance adjusted after a two year lag. This should ultimately impact consumers' electricity and gas bills, but is reliant on the companies' customers, the gas shippers, passing this on.

4.3. Throughout RIIO-T1 we will monitor the TOs actual totex and will compare this with allowances set and companies annual forecast. Companies will have to explain any variances as part of their annual reporting. When looking at the companies' annual performance it is essential to put this in the context that outputs are required to be delivered over the full eight year price control period.

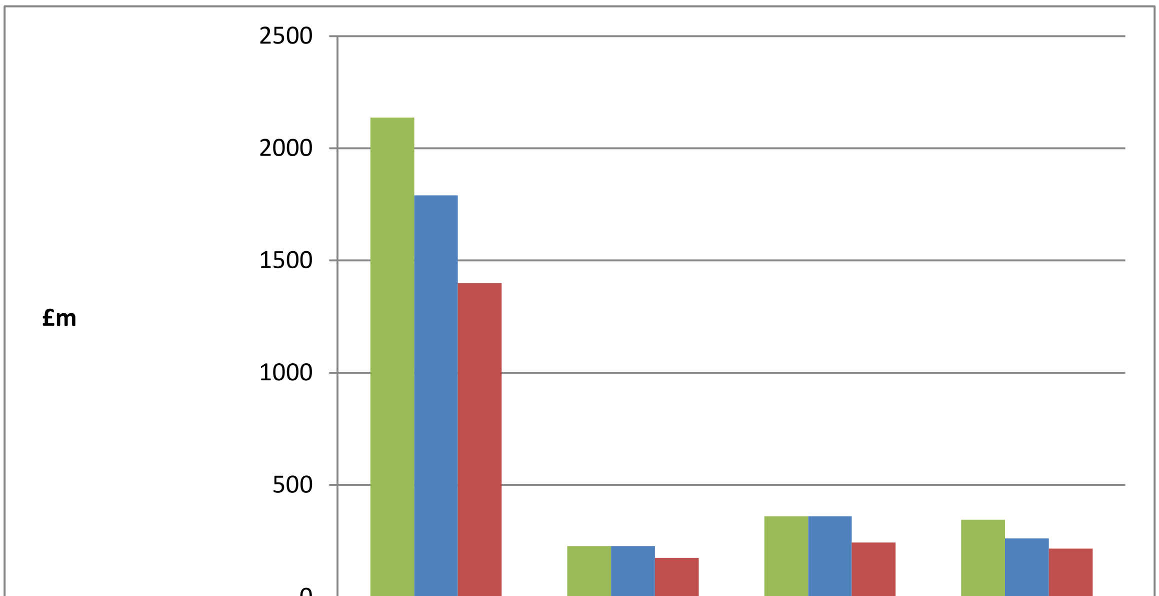
4.4. A fundamental change between the previous price control and the RIIO framework is that companies are free to deliver outputs based on total whole life costs without being constrained to using either operating expenditure (opex) or capital expenditure (capex). This enables companies to select the best solutions and optimises costs and benefits.

4.5. We will still monitor performance against capex and opex allowances to help us understand overall totex performance. For capex, we discuss load-related expenditure (increasing the size or reinforcing the network to accommodate new connections) and non load (expenditure on maintaining the existing network). This chapter therefore goes into greater detail than one might expect in the RIIO price control model. The reasons are: there is no benchmarking between companies as in electricity and gas distribution, the TOs have forecasted significant underspends against allowances, the allowances in some areas relate to single multi-million pound projects, and, we believe some of the changes in forecast will affect how TOs might or might not achieve their outputs.

2013-14 Actual Totex performance

Figure 7 shows performance for all four TOs in 2013-14 not only against the allowance but also against the business plans each submitted to us for the price review. The figures for the Scottish TOs show business plans equalling allowances since we accepted their plans as submitted (and hence they were fast-tracked) in the price control review process.

Figure 7: Actual totex for 2013-14 with allowances



	NGET	SHE Transmission	SPTL	NGGT
Business Plan Forecast	2137.2	227.4	360.9	345.2
RIIO Allowances	1790.1	227.4	360.9	261.4
2014 Actuals	1399.2	174.5	242.8	215.8

4.6. In year one of the price control all TOs underspent their allowances, due in part to lower load-related expenditure. Below is more detail on each TO.

4.7. NGET totex is lower than allowances in 2013-14 due primarily to lower load related capex. The reasons given by NGET are:

- Delivery efficiencies
- Customers are delaying connections
- Delays to some incremental wider works and strategic wider works projects
- Opex for NGET and NGGT is higher than allowances, especially in the case of NGET. This is due to the costs of a reorganisation

4.8. SHE Transmission totex is below allowances due to underspending on load- and non load-related capex. The additional reasons given are:

- Lower load due to planning and consenting issues
- Non load lower than the allowance due to two overhead line schemes being cancelled – superseded by other wider reinforcement schemes

4.9. Where non load outputs are effectively achieved by load expenditure we expect TOs to review the merit of alternative use of the non load allowances to improve asset health elsewhere in the transmission system. This will be taken into account when we review NOMs targets and achievements.

4.10. SPTL totex is below allowances due to underspending on load-related capex, offset somewhat by higher non load-related expenditure. The reasons given by SPTL are as follows:

- Lower load capex lower due to planning and consenting issues (this was a continual problem in TPCR4)
- Non load capex is higher than allowances. As SPT indicated in its business plan, delays in its load programme have meant it has been able to bring forward some non load expenditure. Of note, 130km of overhead line conductor were replaced this year instead of later in RIIO-T1.

4.11. NGGT totex is lower than allowances in 2013-14 due to lower capex. The reasons given by NGGT are as follows:

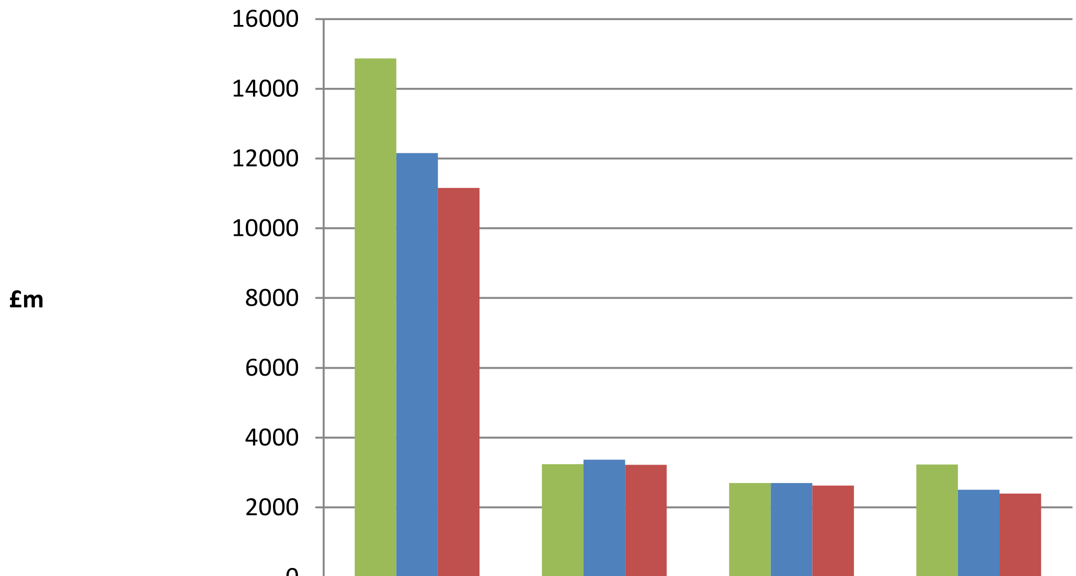
- Lower load-related capex due to a decline in customer activity
- Network flex capex is on hold in Scotland as NGGT are assessing user requirements
- The Avonmouth pipeline reinforcement (incremental capacity) has been delayed as the needs case is being reviewed
- NGGT is implementing a solution to reducing the emissions (Industrial Emissions Directive) at Aylesbury compressor station by using a simpler less expensive one than proposed in the RIIO-T1 business plan

4.12. We accept that some of these reasons are outside the TO's control. Others we believe are within the TOs' control and may have an impact on the TO's output performance later in the period. We accept that many of these reflect an impact in 2013-14 which will unwind over the RIIO-T1 period.

4.13. We will be monitoring these in future years but we expect that TOs will deliver all of their required outputs. Failure to do so will see these allowances clawed back which will benefit consumers.

Forecast performance for the RIIO-T1 period

Figure 8: Forecast totex for RIIO-T1 period with allowances



	NGET	SHE Transmission	SPTL	NGGT
Business Plan Forecast	14870.5	3234.1	2694.3	3228.5
RIIO Allowances	12158.5	3363.0	2694.3	2503.7
2014 Actuals and Forecasts	11153.1	3223.8	2623.2	2392.3

Business Plan Forecast   RIIO Allowances   2014 Actuals and Forecasts

4.14. As well as the performance in 2013-14 we have asked TOs to provide forecasts for the whole of the RIIO-T1 period. In September 2014 NGET published three forecasts, high, central and low. Our analysis is based upon the central forecast (which should represent their 'best view'). The four TOs are all forecasting to underspend their totex allowance. NGET in particular is forecasting, even at this early stage of RIIO-T1, to significantly underspend its allowance. Below is more detail on each TO.

4.15. NGET's forecast Totex for RIIO-T1 is lower than allowances because:

- The economic slowdown since submitting its RIIO-T1 business plan has meant that customers are delaying connections, with some load-related work being delayed until RIIO-T2, and delays to incremental and strategic wider work.
- Non load-related capex is expected to be lower than allowances due to new management approaches and efficiency measures reducing overall costs while delivering target outputs.

4.16. It should be noted that where outputs are delayed beyond RIIO-T1, NGET's RIIO-T1 allowances will be reduced by the volume driver mechanism. We consider this and non related efficiencies in section 4.23 onwards.

4.17. SHE Transmission's forecast totex for RIIO-T1 is lower than allowances because:

- Load-related connections capex is expected to be lower reflecting efficiency in delivery and some gains from baseline funding where schemes are no longer required (eg OFTO connection to Argyll Array).
- There is a small opex saving forecast which mainly reflects lower business overhead costs

4.18. At the moment, we are unsure how these efficiencies will be delivered. We will seek further clarification from SHE Transmission with next year's submission.

4.19. SPT's forecast totex for RIIO-T1 is almost in line with allowances:

- The volume of renewable generation in Scotland is uncertain and volatile which means forecasting is difficult and the allowances are set to reflect actual outputs delivered. Load-related connections volumes over the whole period are expected to be higher than baseline assumption, which will trigger additional allowances.

- SPT has reacted to delays in its load-related activity by bringing forward non load expenditure. It explains that this approach will allow it to deliver more load related activity later in the period.

- SPT has indicated that despite its claim that the volume driver unit cost being set too low and connection volumes expected to be higher, it will underspend the load-related allowances by c. £110m. At the moment we are unsure how it will deliver, and will seek more clarification from SPT.

4.20. NGGT's forecast totex for RIIO-T1 is lower than allowances because:

- Lower load-related capex is significantly lower at £200m (85%) below allowances. A number of external factors that are influencing the economic case for the development of gas projects in the UK, resulting in a challenging investment environment for new gas-fired generation

and storage. NGGT now expect limited load-related investment on the system.
- Non load-related capex is expected to be higher than allowances with additional investment proposed to address emissions issues. This is a significant area of investment which we plan to scrutinise later in 2015.

4.21. We give further detail on NGGT delivery in paras 4.64 below.

4.22. The forecast expenditure and comments highlight what areas of performance we should focus our monitoring in future years. These are:

- Network Output Measures (NOMs) for all TOs. We will closely monitor whether the targets at the end of RIIO-T1 are achieved. We are working with TOs to further develop the NOMs methodology. Amongst other things, this would help inform our assessment of how NGET achieve the non-load capex savings.

- TOs' achievement of efficiencies. We will examine in more detail how the delivery efficiencies claimed by the TOs are achieved.

- NGGT plans not to do some doing work that it highlighted as 'essential' in its RIIO business plan, eg Avonmouth reinforcement, and for which funding was allowed.

- NGGT is forecasting an overspend of non-load allowance, reflecting substantial investment in reducing emissions. As indicated above we shall be focussing on this later in 2015.

Network capital expenditure (Capex) and forecasts

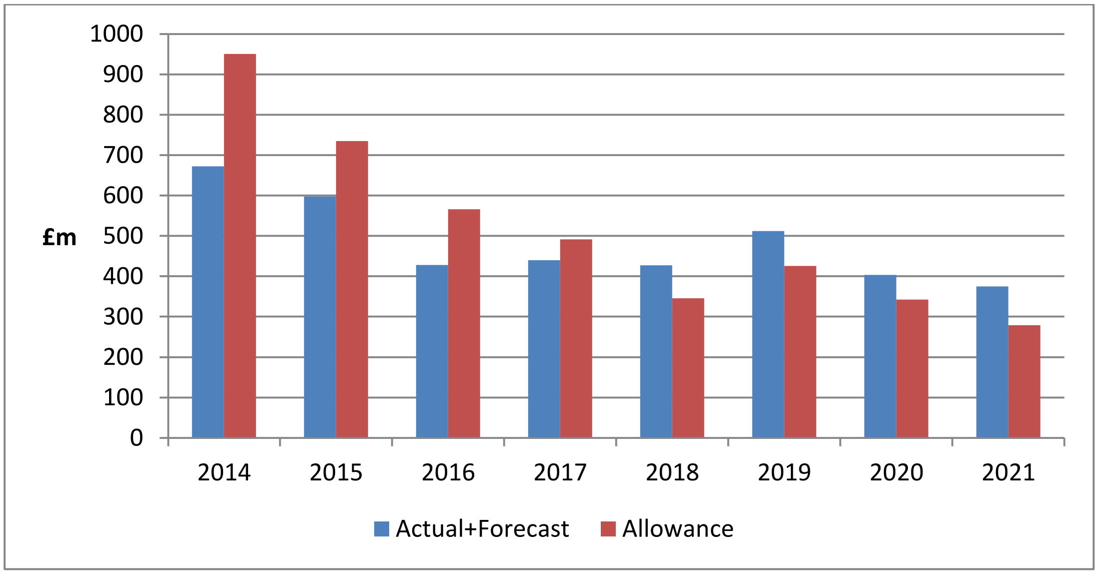
4.23. Capex is divided into load-related and non load-related. Load-related is the installation of new assets on the network to accommodate changes in the level or pattern of electricity or gas supply and demand. Non load-related expenditure is expenditure that is spent on maintaining the existing network rather than to increase capacity. Typically, this will be asset replacement or refurbishment.

Electricity load-related

4.24. Figure 9 below shows a breakdown of 2013-14 actual and latest forecast load related capital expenditure for each TO against their allowances. It should be noted that the current load-related capital expenditure forecasts from each TO differ from their initial business plan submission to Ofgem in 2012. This was expected since load-related expenditure relies heavily on generation and demand connections materialising (over which TOs have little influence). We have therefore reassessed the current year and forecast allowances in line with the relevant uncertainty mechanisms and based on TO forecast outputs.

NGET

Figure 9: NGET actual (2013-14) and forecast load related expenditure v forecast allowances



4.25. NGET has underspent on load-related capital expenditure by £278m against its revised allowance in 2013-14. It explains that this is in part due to delivery efficiencies and outputs delivered where the bulk of expenditure was incurred during the TPCR4 price control review period.

4.26. NGET delivered 746MW of generator connection outperforming its baseline forecast output. NGET has an additional volume driver for overhead lines required for generation connection. During the 2013-14 period no overhead lines have been required for generation connections. Therefore the volume driver for overhead lines has not been triggered and no allowances have been included in this year's load related allowance.

4.27. In terms of demand related infrastructure outputs, NGET installed two new super grid transformers with no requirements for overhead line, against its baseline outputs of 4 SGTs and 7km of overhead line.

4.28. In terms of wider works outputs, NGET have delivered 1100MW across boundary EC3 and a 1000MW across boundary EC5 through the extension of Bramford Substation and re-conductoring of Walpole-Norwich Main overhead line.

4.29. 600MW of boundary capability, across boundary B7, has also been delivered through the re-conductoring of Harker - Hutton - Quernmore circuit. According to its baseline outputs, this was expected to be completed in 2014-15 but has been delivered earlier. These works, when combined with the series and shunt reactive compensation project, are expected to deliver a combined capacity increase of 1000MW for boundary B6 and 1400MW for boundary B7 during the 2014-15 period.

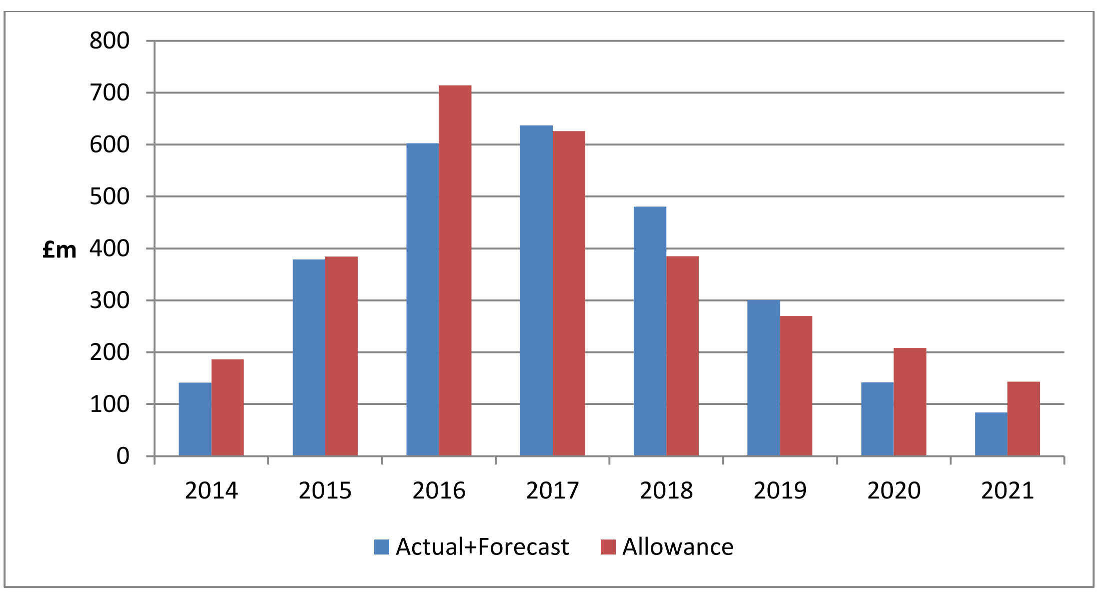
4.30. By 2018 NGET's load-related expenditure is forecast to exceed allowances as project investment to deliver transmission network capacity, for generation and demand connecting in later years, increases. This trend is expected to carry on until the end of the RIIO-T1 period as projects are delivered and generation and demand connections materialise.

4.31. NGET has stated that fewer generation and demand connections are now being required compared to the baseline allowances and outputs. This reduction in generation and demand also reduces the need for incremental wider works, which would have otherwise been needed to resolve boundary capacity constraints on the transmission system.

4.32. NGET claims the out performance over the remaining RIIO-T1 period is due to the delivery of the load-related capital programme in a more efficient way. It has, for instance, reduced the number of delivery contractors for overhead line and substation construction from eight to five, and broadened its contracting approach with supply chain partners. It explains that the expected delivery efficiencies are common across NGET's entire capital programme and therefore relate also to its non-load related investments. See the Electricity Non Load-Related section below for further discussion of delivery efficiencies.

SHE Transmission

Figure 10: SHE Transmission actual (2013-14) and forecast expenditure vs forecast allowances



4.33. SHE Transmission has underspent on load-related capital expenditure by £45m against its revised allowance in 2013-14.

4.34. SHE Transmission delivered the required substation works for the Beauly-Mossford overhead line project as part of their baseline wider works outputs in 2013-14. The Beauly-Mossford overhead line scheme is funded via two different mechanisms and over two different price controls. The substation works started off in TPCR4 and was funded through the TII[20] mechanism. It is now part of the base line wider works in RIIO-T1 and was completed by March 2014. The remaining overhead line related work received funding approval in August 2014 via the strategic wider works RIIO-T1 mechanism. However for 2013-14 no boundary transfer benefit has been recorded for Sub-Boundary B10. The expected boundary benefit of 252MW can only be achieved when the entire scheme is completed by 31 December 2015.

4.35. SHE Transmission has also delivered 217MW of new generation connections.

4.36. SHE Transmission explains that its underspend on load-related capital expenditure was through connection scheme terminations and delays, efficiency savings on particular projects such as Dounreay, Berryburn, Shin & Alness schemes and on the timing difference between investment from previous price control regimes and delivery in the current year.

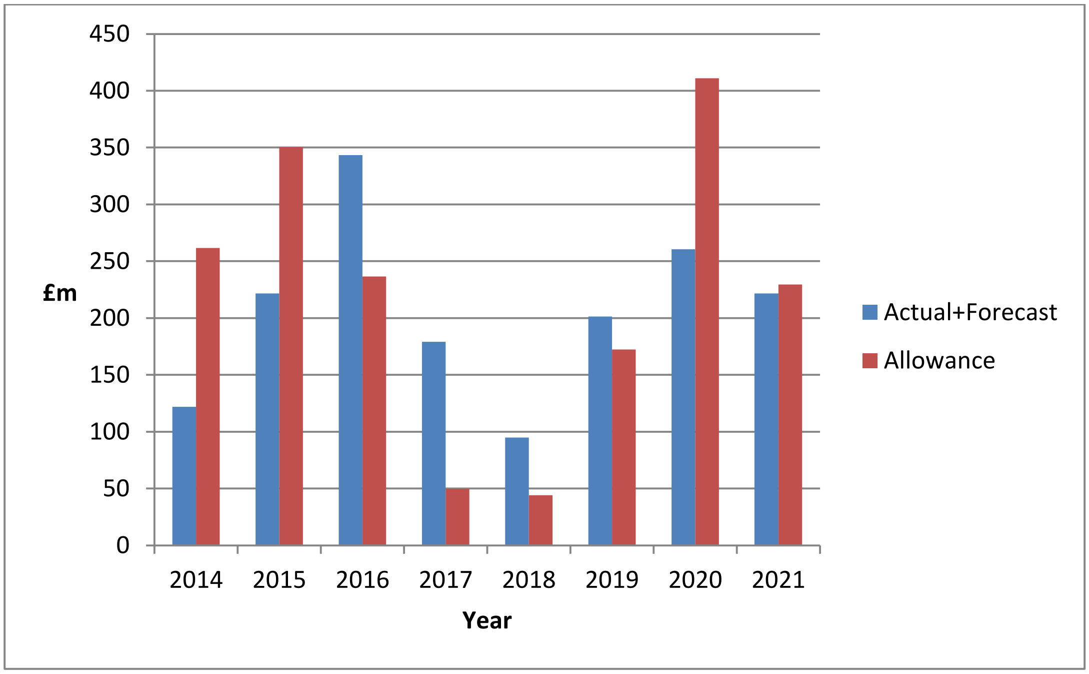
4.37. SHE Transmission has forecast an outperformance of c. £150m against its forecast allowances over the RIIO-T1 period. We expect future annual submissions will further explain where the efficiencies have been put in place by SHE Transmission to achieve this.

4.38. As with NGET's forecast, SHE Transmission's forecast also shows expenditure outstripping allowances from 2017 before the trend is reversed as connections materialise.

[20] TII in April 2010 to provide project-specific interim funding for investment projects that did not have funding under TPCR4

SPT

Figure 11: SPT actual (2013-14) and forecast expenditure vs forecast allowances



4.39. SPT have underspent on load-related capital expenditure by c£140m against its reassessed allowance in 2013-14. This reflects delays caused by consenting issues but the company expect to catch up this over the remaining period of RIIO-T1.

4.40. In 2014 SPT has delivered 400MW of sole use generation connection capacity and 240MVA of shared use generation connection capacity.

4.41. Approximately £100m of the expenditure in 2013-14 was on wider works projects including West Coast HVDC, series compensation and East-West projects.

4.42. Two local enabling exit infrastructure schemes (Grid Supply Points (GSP) reinforcements) have been delivered.

4.43. A few schemes that were in the baseline at RIIO-T1 have subsequently terminated (e.g. Andershaw and Rowantree). New contracted schemes are in early-stage development, incurring small investment in the 2013-14 period. In the south-west of Scotland planning difficulties have necessitated a re-profiling of investment, with an 18-month delay associated with providing the necessary 275kV and 132kV infrastructure. Other schemes such as Moffat substation commissioned in 2013-14, have been delivered earlier than expected with the bulk of investment having taken place outside of the reporting period.

4.44. This re-profiling of investment has led to the significant underspend in the current year (but was identified as a possibility in the company's business plan).

4.45. Overall SPT is forecasting an underspend of £111m compared to its revised allowances over the RIIO-T1 period.

4.46. Renewable generation connection activity is forecast to increase to around 4GW compared to the baseline of 2.5GW. SPT expects this to result in increased shared infrastructure assets to support the potential increase in connected generation. Strategic Wider Works projects included in the RIIO-T1 submission such as Dumfries and Galloway upgrade (c£320m), east coast 400kV onshore upgrade and the Central 400kV onshore upgrade (c£110m) are also expected to be triggered.

4.47. SPT's forecast also shows that expenditure is expected to increase above allowances after 2016 before this trend is reversed with the bulk of connections materialising in 2020.

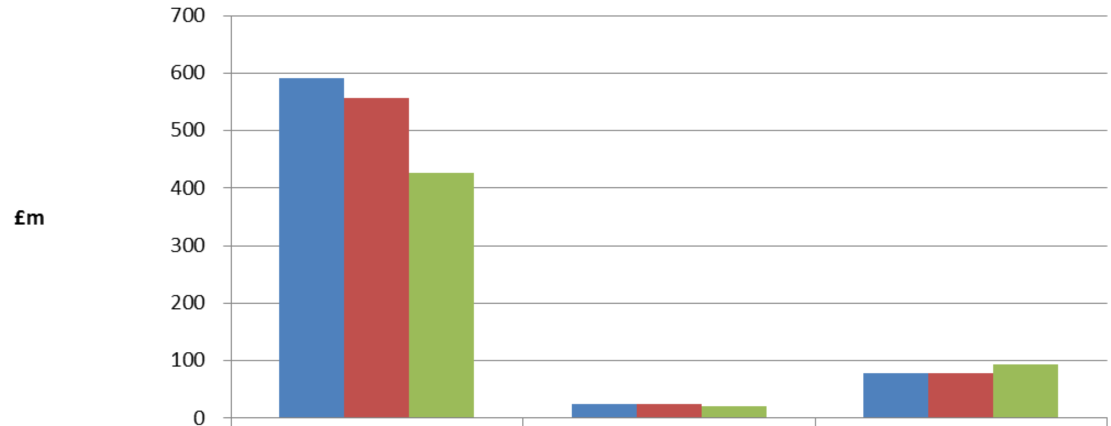
4.48. All three electricity TOs have highlighted that the uncertain nature of the generation and demand backgrounds has resulted in significant re-profiling of project expenditure and delivery when compared with the initially submitted RIIO-T1 business plans. The revenue drivers and the corresponding uncertainty mechanisms within the price control will automatically adjust allowances if fewer outputs are delivered. However, the timing of this adjustment depends on when the future output was expected to be delivered.

4.49. We will carry out in depth investigation into the claims of efficiency savings from all TOs. To enable us to verify efficiency savings as RIIO-T1 progresses through the eight years, we are modifying our forthcoming annual reporting processes. This will require TOs to report further information on efficient delivery and on project progress.

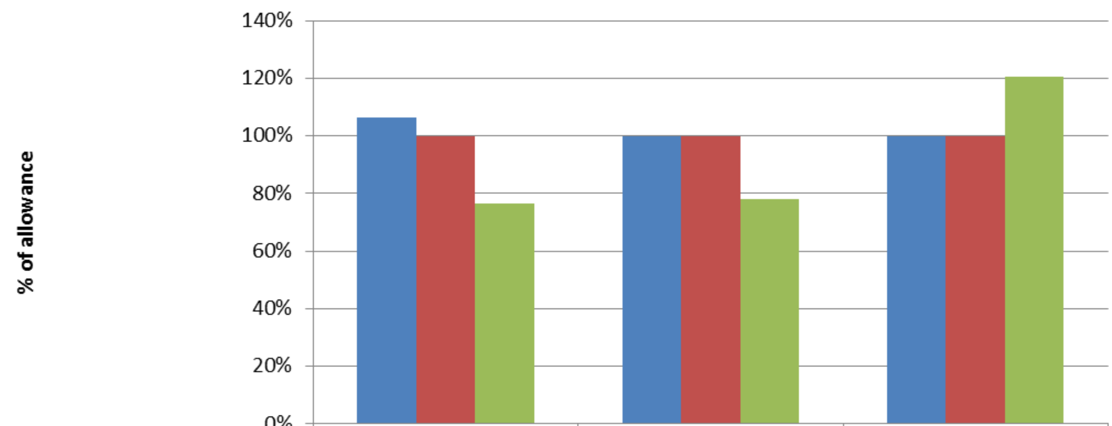
Electricity non load-related

4.50. Figures 12 and 13 show how the electricity TOs have performed in 2013-14 and their non load-related capex forecast for the RIIO-T1 period.

Figure 12: Electricity non load related actual 2013-14 expenditure and percentage of allowance

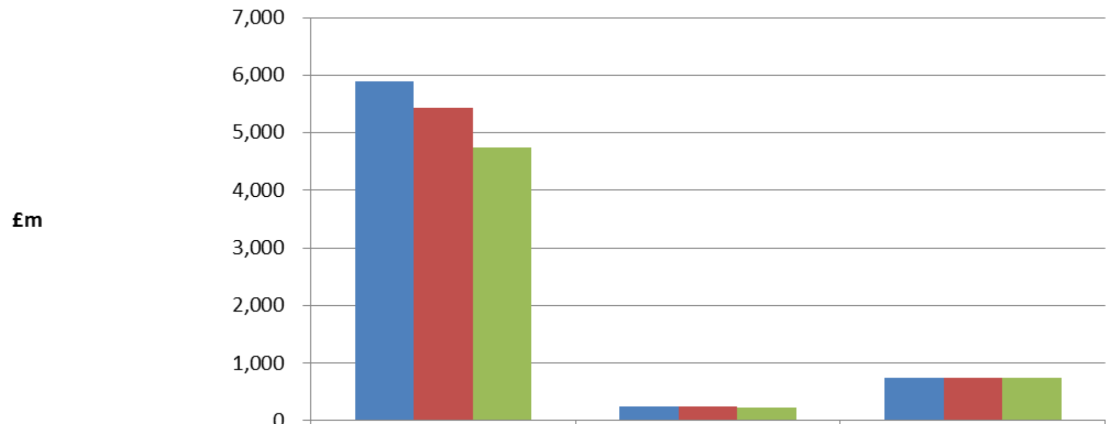


	NGET	SHE_T	SPT
RIIO-T1 Business Plan	592	25	78
Allowances	557	25	78
NLR Expenditure	427	20	94



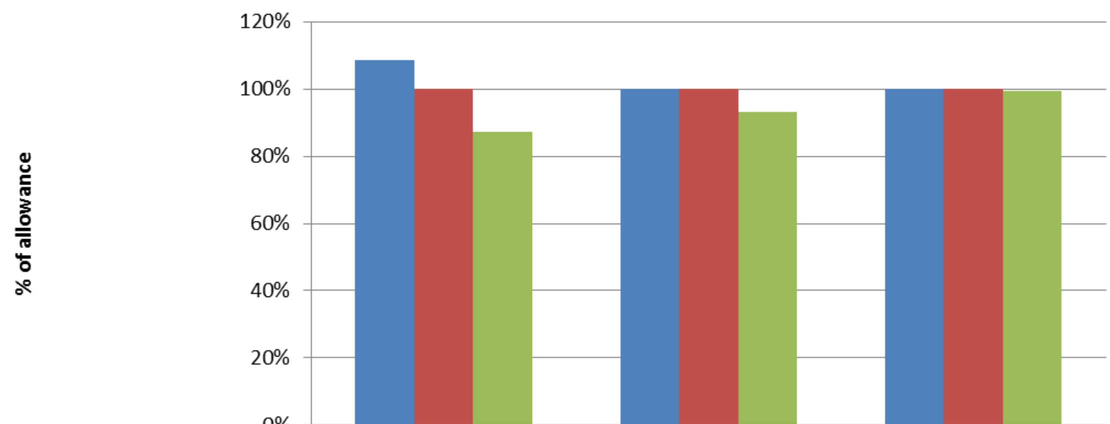
	NGET	SHE_T	SPT
RIIO-T1 Business Plan	106%	100%	100%
Allowances	100%	100%	100%
NLR Expenditure (Normalised)	77%	78%	121%

Figure 13: Electricity non load related forecast for RIIO-T1 and percentage of revised allowance



	NGET	SHE_T	SPT
RIIO-T1 Business Plan	5,900	244	751
Allowances	5,435	244	751
NLR Expenditure (Normalised)	4,741	228	747

RIIO-T1 Business Plan   Allowances   NLR Expenditure (Normalised)



	NGET	SHE_T	SPT
RIIO-T1 Business Plan	109%	100%	100%
Allowances	100%	100%	100%
NLR Expenditure (Normalised)	87%	93%	99%

RIIO-T1 Business Plan   Allowances   NLR Expenditure (Normalised)

4.51. NGET and SHE Transmission underspent on non load-related capex in 2013-14 and are forecasting overall underspend over RIIO-T1.

4.52. As was outlined in its business plan submission SPT has taken advantage of its early settlement of the RIIO-T1 price control arising from its fast-track status to accelerating its replacement programme. Further acceleration has been made possible due to delays in load related investment. This has meant a 21% over-spend on non load-related activities (£16.1m) in 2014. However, we note that expenditure is forecast to drop off towards the end of RIIO-T1 resulting in total forecast expenditure that is roughly in line with allowances.

4.53. NGET has indicated that it will achieve an estimated £831m of savings on its non load-related programme. It expects to achieve these savings through a combination of innovation (£375m) and delivery efficiencies (£456m). NGET explained that the savings through innovation are related to rebalancing refurbishment and replacement of circuit breakers, targeted partial replacement of overhead line fittings, and using enhanced paint coating system. It also gave the main sources of delivery efficiencies as organisational redesign and revision to its procurement and contracting arrangements.

4.54. To help us better understand the true extent of efficiency savings and the robustness of NGET's business planning process, we will consider revising the regulatory reporting requirements to provide more visility in this area. We will also examine as part of our ongoing NOMs work the impact of revised non load-related programme on relevant outputs.

Non load related outputs

4.55. The main non load related outputs are replacing and refurbishing Primary Plant Type (Lead) Assets[21] and are captured by the NOMs. All three ETOs claim to be on target to deliver non load-related outputs by the end of RIIO-T1. We are currently working with ETOs to further develop the NOMs methodology by the end of 2015. We expect the methodology to help us assess whether the companies' replacement and refurbishment programmes deliver appropriate levels of outputs and whether these have been delivered efficiently.

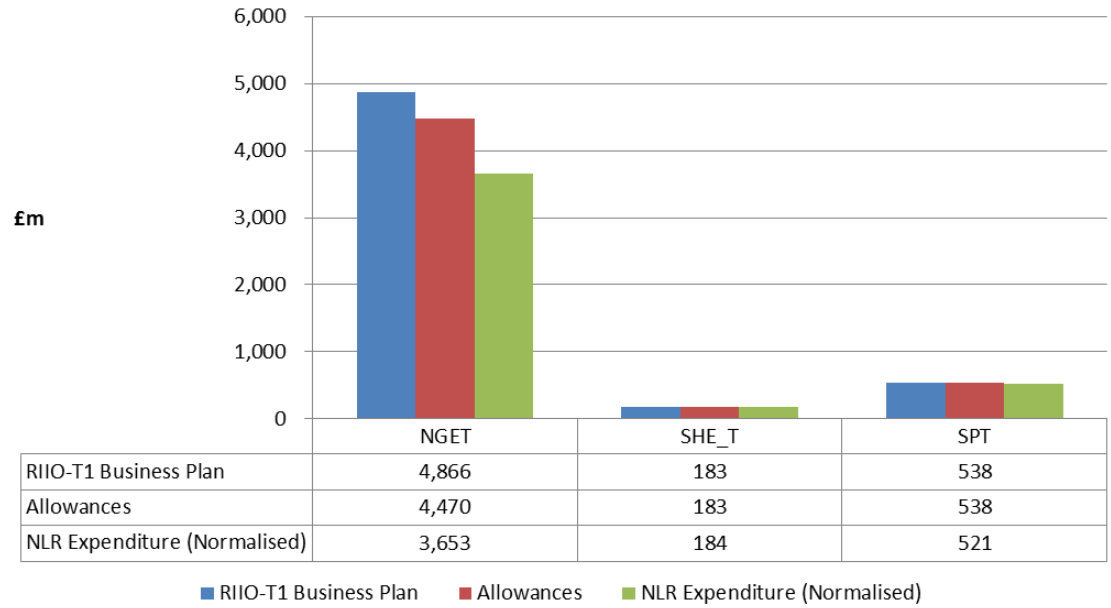
4.56. While SHE Transmission's and SPT's forecast expenditure on Primary Type Assets is in line with allowances, NGET expects to underspend by approximately £817m[22] while still delivering equivalent outputs. NGET's savings are partially offset by a £122m forecast overspend on non primary type (non lead) assets. In our future work we will monitor NGET's expenditure on non-lead assets and seek evidence of additional output delivery for the forecast overspend on non lead assets and how this might be impacted by any savings resulting from innovation.

4.57. Figure 14 show the forecast level of capex relating to primary assets compared to allowances.

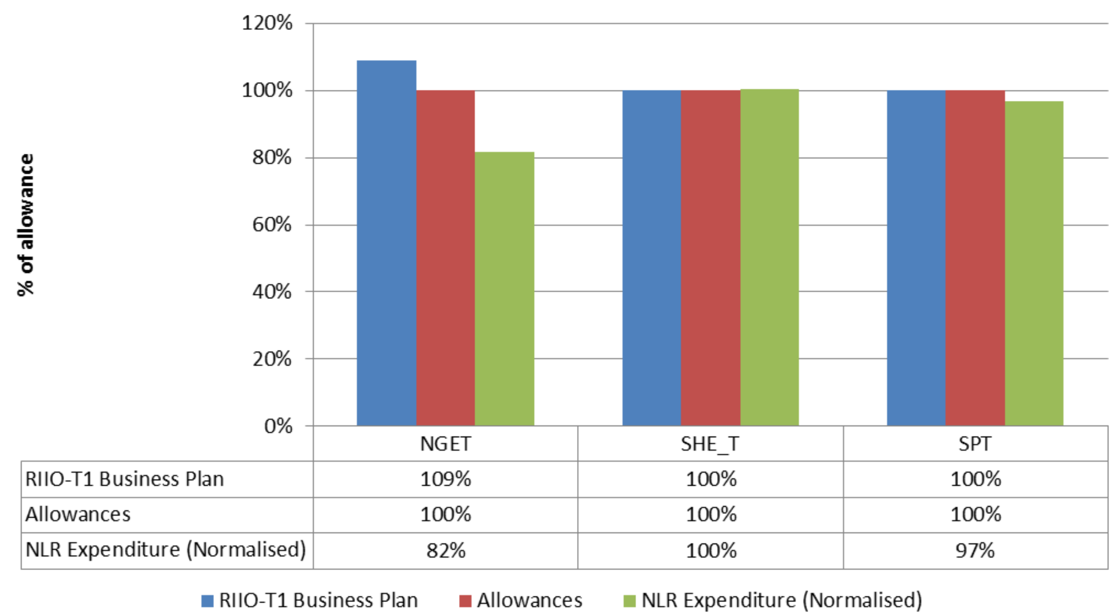
[21] Primary or lead assets are the main assets comprising the transmission network that are required for the safe and reliable transfer of electricity from one point on the network to another. They do not include for example monitoring, telecommunications, or protection equipment (except for switchgear). For reporting purposes the following asset categories are lead assets: Switchgear (circuit breakers), overhead lines, transformers, underground cables, cable tunnels.

[22] We have adjusted submitted allocation between lead and non lead assets to provide a like for like comparison with allowances.

Figure 14: NLR capex primary plant forecast for RIIO-T1 and percentage of revised allowance



	NGET	SHE_T	SPT
RIIO-T1 Business Plan	4,866	183	538
Allowances	4,470	183	538
NLR Expenditure (Normalised)	3,653	184	521



	NGET	SHE_T	SPT
RIIO-T1 Business Plan	109%	100%	100%
Allowances	100%	100%	100%
NLR Expenditure (Normalised)	82%	100%	97%

Gas

NGGT capex

4.58. NGGT received £1281m for capex for RIIO-T1. The actual spend in the 2013-14 year has been £122m against funding of £167m. Figure 15 below shows NGGT's overall capex delivery compared against allowances[23]. Figure 16 shows the forecast profile of expenditure during RIIO-T1.

Figure 15: NGGT load and non load capex against allowances 2013-14

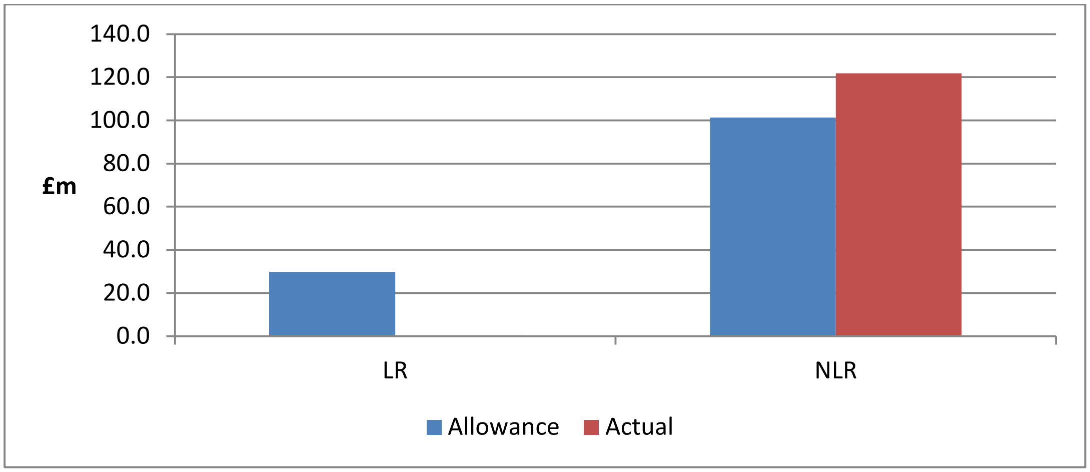
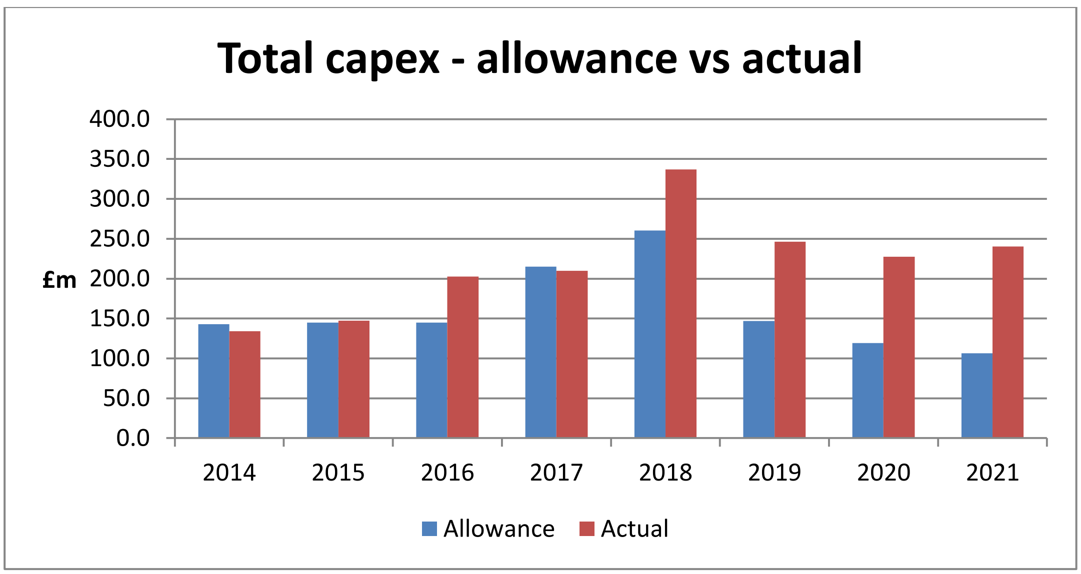


Figure 16: NGGT forecast capex profile against RIIO-T1 allowances



Forecast performance during RIIO-T1

4.59. In light of RIIO-T1 allowances, NGGT's forecast is to underspend its totex allowance by approximately £111m throughout RIIO-T1 (as reflected in Figure 8 above). We are mindful of the potential revised delivery of the capex in terms of load-related projects, such as the Avonmouth pipelines and the deferral of flexibility expenditure, and in terms of non load-related projects, such as the compressors'

[23] Excluding non-operational capex see section 4.73 below

emissions projects and continued underspend in Asset Health. Ofgem's view is that these could result in a total underspend of approximately £400m. We comment further on these projects below.

NGGT load related capex

4.60. Figure 17 below shows the comparison between allowances and actual spend for Load related capex for 2013-14.

4.61. NGGT was funded primarily to deliver the following projects:

- Network capability to maintain the 1-in-20 obligation in Scotland. This involved projects at strategic locations within the National Transmission System (NTS), such as reverse flow modifications at compressor sites. These projects were aimed at reversing flows of natural gas towards Scotland in order to replace declining volumes of UKCS gas in case of a 1-in-20 demand scenarios;
- Two 900mm pipelines ('pipeline solution') as a replacement of the Avonmouth LNG storage facility, which was expected to be decommissioned in 2018. This solution was the one proposed by NGGT in its RIIO-T1 business plan as the most appropriate one through its optioneering. In order to avoid risks relating to security of supply, Ofgem provided funding for the two pipelines.

4.62. In its submission, NGGT has signalled that:

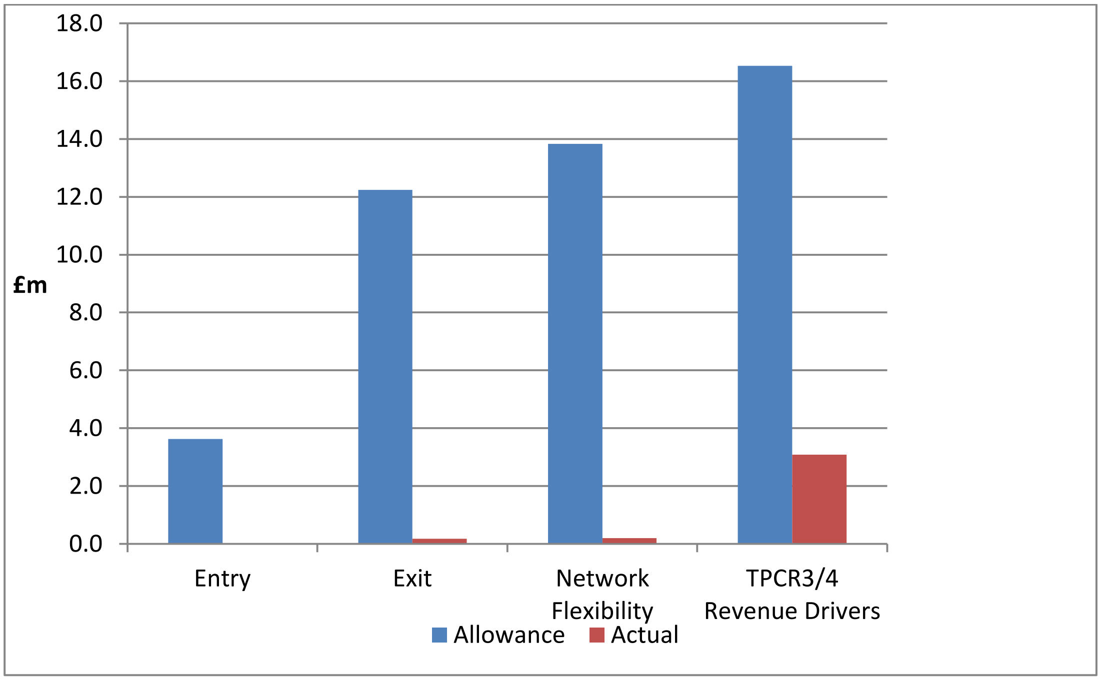
- The projects for the 1-in-20 obligation in Scotland will be deferred. More specifically, NGGT used updated supply and demand information to see what physical reinforcement of the network was still required to meet the demand obligations in Scotland. However, the forecast rate of decline of flows from the St. Fergus terminal has reduced. As a result the required reinforcement has been pushed back in the investment plan. No clear indication has been given for a delivery timeline, or for which projects will be delivered. NGGT has indicated it will identify efficiencies in delivering these projects alongside future non-load related investment required for environmental compliance purposes;

- A different approach, eg a commercial solution, is more appropriate for Avonmouth as a solution and NGGT will explore this further with its stakeholders. More specifically, at the start of the RIIO-T1 period, NGGT updated its analysis in order to review the needs case for the project before initiating the expenditure. This involved further consideration of updated supply and demand information and expected future customer requirements. As a result, NGGT will engage with stakeholders to fully understand the range of options that will enable it to deliver the Avonmouth related outputs, ahead of significant investment in the pipelines.

4.63. As a result of the above, NGGT is underspending on its allowances on the first year of RIIO-T1 as can be seen in Figure 17 below.

4.64. NGGT is forecasting a significant underspend against the forecast and allowed TPCR3 and 4 revenue drivers. This underspend will be removed at the end of RIIO-T1 as part of the next price control review.

Figure 17: NGGT Load-related capex vs actual spend 2013-14



NGGT Non load-related capex

4.65. This area comprises expenditure from reducing the direct emissions resulting from the operating the compressors' fleet, and asset health (replacing assets in danger of failing) in order to maintain the NTS.

Emissions expenditure

4.66. NGGT was primarily funded to deliver the following explicit outputs:

- Two new compressor units at Aylesbury compressor station – one gas turbine driven and one electric-driven; and

- Two new electric-driven compressor units at Peterborough and Huntingdon (one at each site).

4.67. NGGT has signalled (in its submission and through its recent Industrial Emissions Directive (IED) consultation document) that:

- Its current expenditure is still focused on emissions projects that were initiated during TPCR4. The reason is that a main works contractor fell into administration at the closing stages of TPCR4. Therefore, NGGT was forced to prioritise the delivery of these projects in the compressor stations at St. Fergus, Kirriemiur and Hatton. Also, NGGT has completed the final tests of the new units. Therefore, commissioning of the stations is underway in winter 2014-15.
- It will install catalytic converters at the existing compressors' stacks to deliver compliance.
- It will install one new gas turbine-driven compressor at Huntingdon and a gas turbine driven one in Peterborough.

4.68. However, NGGT is underspending compared to allowances and its expenditure relates to TPCR4 emissions projects which have yet to be delivered. Also, the allowances set for Peterborough reflect the unit cost of an electric-driven compressor, which are higher than a gas turbine driven one.

4.69. In light of this revised approach by NGGT we will look at any approaches for additional funding at either the mid-period review or reopener windows taking consideration of this funding which NGGT does not now appear to require. We will investigate further the impact of the introduction of the new compressor units in the operation of the entire fleet, ie the resulting reduction in the operation of other compressor units. This will be useful for avoiding future unnecessary investment.

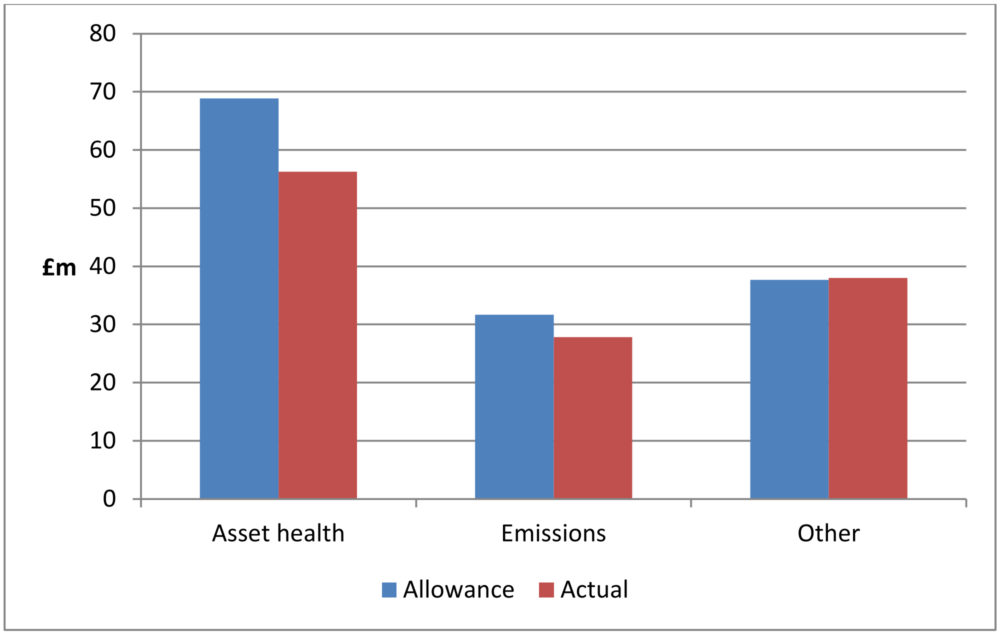
Asset Health

4.70. Expenditure was set against historic spending levels and NGGT's justification of its requirements. NGGT's current underspend reflects a different approach to delivering the capex and prioritising in specific secondary assets. More specifically, NGGT says that it has targeted the secondary assets with the highest priority within the NOMs. As a result of this and the volume discounts, ie economies of scale in focusing its efforts, it is able to deliver the works more efficiently.

4.71. Therefore, NGGT's outperformance may be considered as one based on efficiencies and innovation. However, we do note that NGGT's requests for funding Asset Health expenditure in relation to the Bacton terminal and its reconfiguration, have not been incurred and NGGT is managing the condition of the terminal within its existing allowances without incurring expenditure.

4.72. Additionally, although the NOMs methodology is not clearly progressed, we have concerns that the forecast underspend will impact on the achievement of NOMs targets. We will work closer with NGGT to further understand this and to make the NOMs an accurate and robust tool for future allowances requests and verification of the NTS condition. Figure 18 below shows the comparison between allowances and actual spend of non load-related capex.

Figure 18: Non load related capex restated allowances vs actual spend 2013-14



Non-operational capex

4.73. Non-operational capex is expenditure on assets other than network assets. The areas of expenditure are information technology (IT), land and buildings, vehicles and tools and equipment. For all TOs the main type of this expenditure is IT, both hardware and software.

4.74. For SHE Transmission and SPT, non-operational capex expenditure is comparatively small, less than £2m per year for both. In the case of NGET and NGGT the allowances assumed they would spend on average £22m and £8m per year respectively over the eight years of RIIO-T1. They forecast that more would be spent in the first few years when NGET and NGGT expected to undertake two new IT projects to assist in making efficiencies and savings within direct opex and non load-related capex.

4.75. In 2013-14 NGET has spent £35.8m; slightly more than its allowance (£33.2m), but has forecast to spend broadly in line with allowances over RIIO-T1. NGGT spent almost as allowed (£12m).

Operating costs (Opex) and forecasts

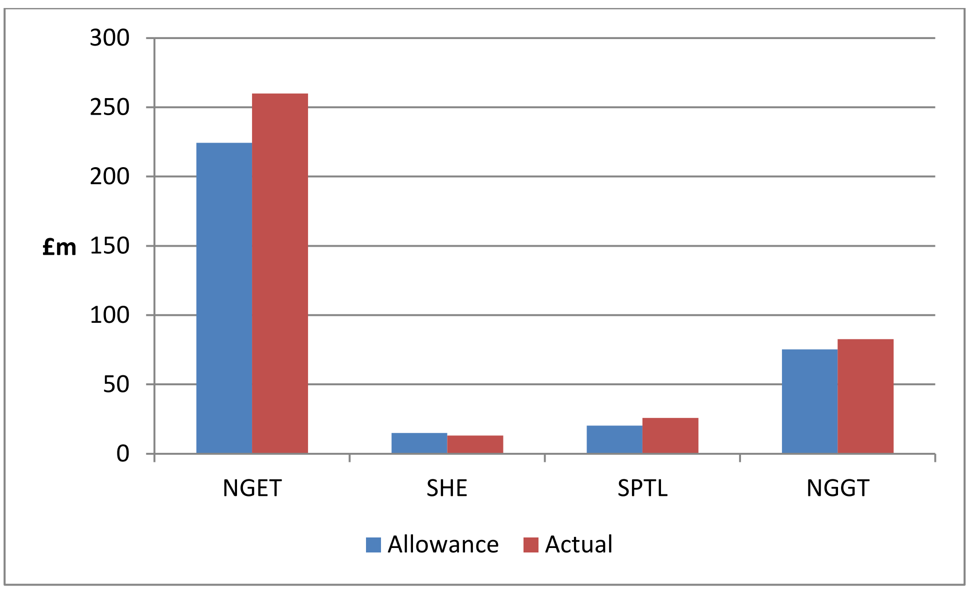
4.76. Operating expenditure (opex) are the costs incurred in the day to day operation of the network. Opex can be further split into:

- Direct opex
- Business support costs
- Closely associated indirect costs (CAI)

4.77. 'Direct opex' refers to inspections and maintenance of network assets. 'Business support' refers to costs which support the overall company such as IT, telecoms, property management and insurance. 'CAI' refers to costs which are linked, but not directly related to capex and direct opex activities. This includes operational training, engineering management and project management costs.

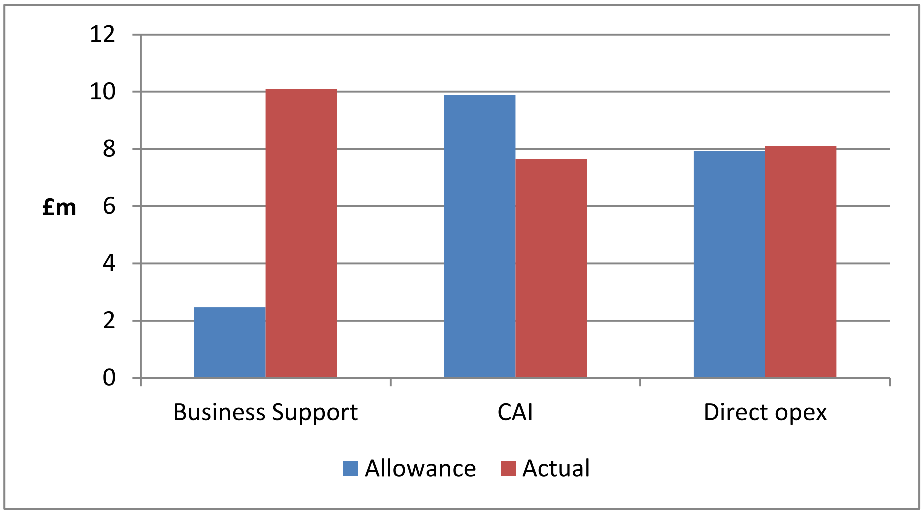
4.78. The chart below shows the companies' actual costs for 2013-14 compared to their allowance set under the RIIO-T1 price control.

Figure 19: Opex allowances compared with actual spend – 2013-14[24]



[24] Actuals figure excludes uncertainty mechanisms, pensions and decommissioning, but has been adjusted for movements in provisions.

Figure 20: SPT opex allowances compared with actual spend



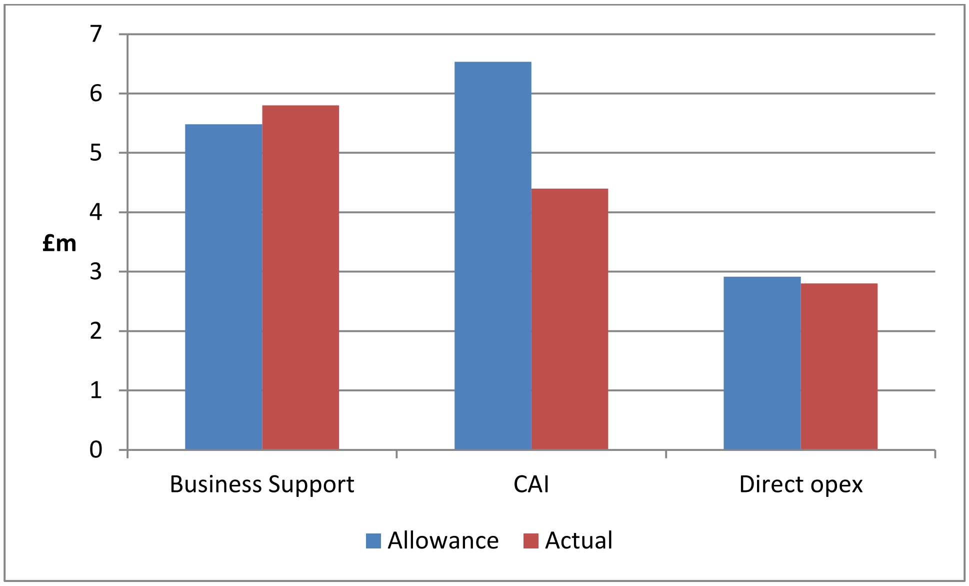
4.79. SPT has spent significantly more (27%) than its allowances.

4.80. SPT business support costs have increased from the RIIO-T1 allowance of £3m to £10m. The main reason for this increase is due to a review of the accounting procedures for fixed assets in order to bring this into line with the rest of the industry[25]. SPT states that the impact of this will result in a reduction in capex project costs of approximately £60-65m during RIIO-T1 with a corresponding increase in business support costs. We will continue to monitor this during RIIO-T1.

4.81. CAI costs have also decreased due to the impact of delays to some load related projects. These are due to delays in obtaining landowner agreements and necessary consents for wider works and other capex projects.

[25] P.13 http://www.spenergynetworks.co.uk/userfiles/file/SPT_2013_14_Annual_Performance_Report.pdf

Figure 21: SHE Transmission opex allowances compared with actual spend



4.82. SHE Transmission has underspent its allowance by -13%.

4.83. SHE Transmission CAI costs have decreased from £7m to £4m. This is due to:

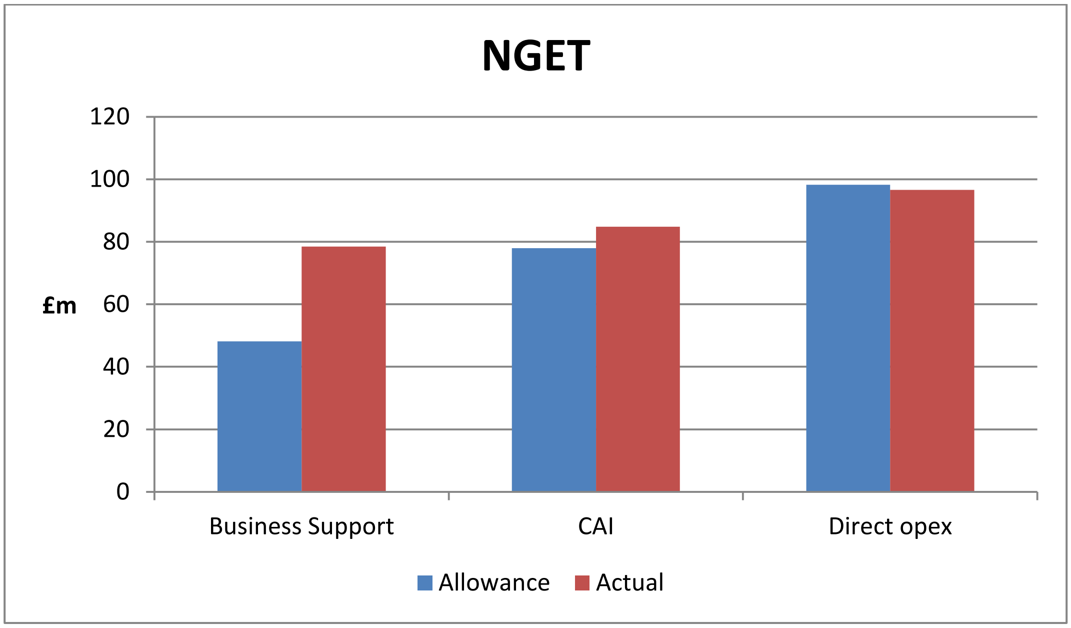
a) SHE Transmission not recruiting additional staff as indicated in its RIIO-T1 business plan.

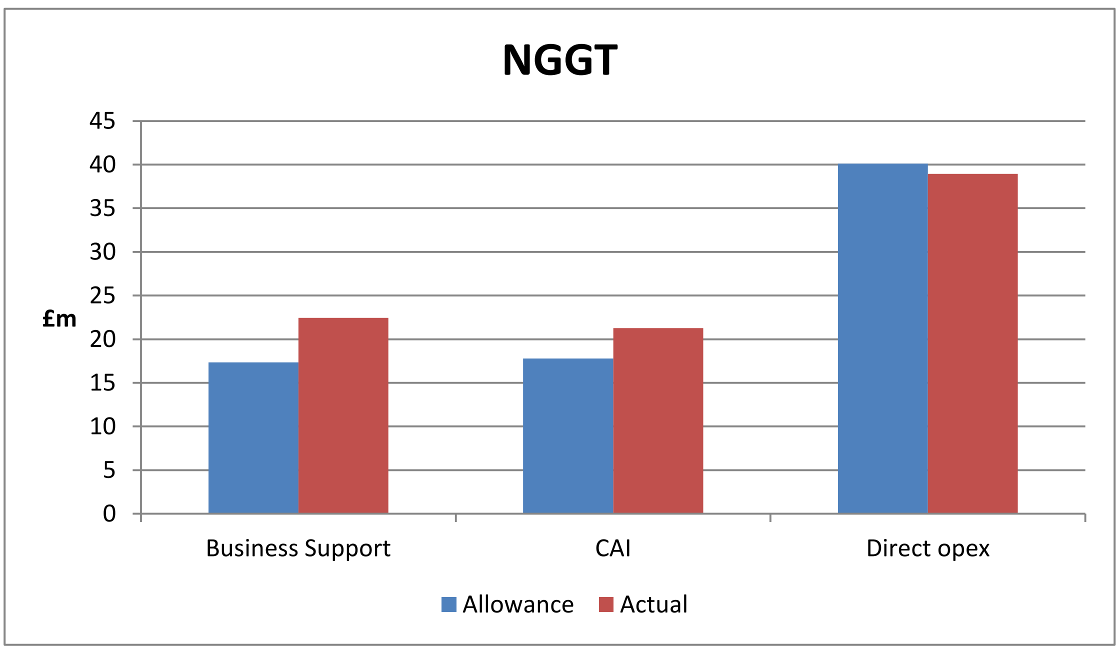
b) Lower network design and engineering and network planning costs.

4.84. SHE Transmission's business plan had stated that additional staff would be required to work on the EU third package, network codes, pricing and forecasting. It has confirmed that it still intends to recruit additional staff and we will monitor this during RIIO-T1.

4.85. Network design and engineering and network planning costs are lower than forecast as the majority of projects are still underway and so their costs are capitalised. Costs are expected to increase once these projects are completed.

Figure 22: National Grid opex allowances compared with actual spend





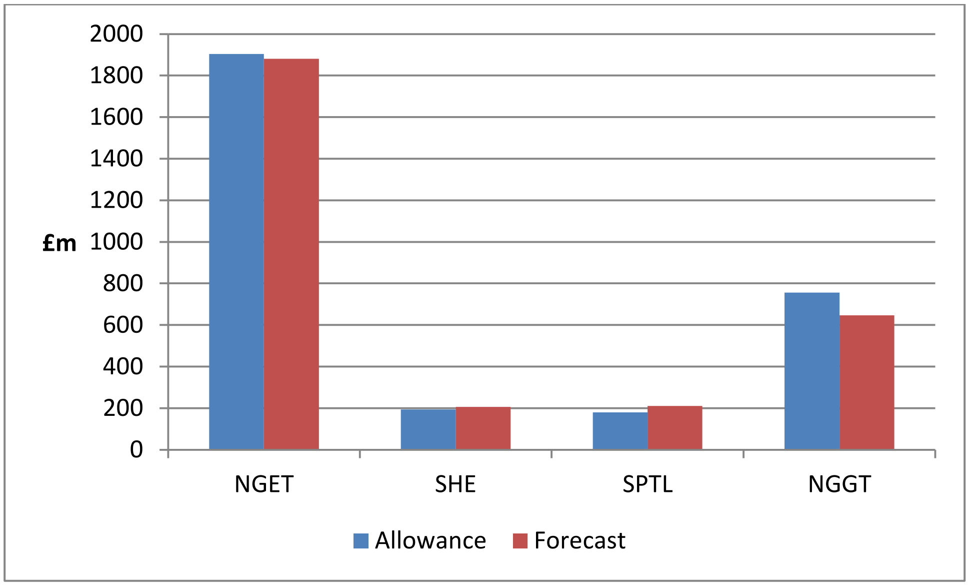
4.86. NGET has spent 16% more than its allowance while NGGT's expenditure is 10% above its allowance.

4.87. Business support costs have increased from their allowance of £48m to £79m for NGET and from £17m to £23m for NGGT. These increases are partially due to an increase in costs due to the organisational changes which are expected to lead to cost savings of over £150m across both NGET and NGGT during RIIO-T1. However, this does not fully explain the increase and we will continue to closely monitor these costs to ensure these savings are achieved.

4.88. Direct opex actual costs are broadly comparable to allowances for both NGET and NGGT.

Forecasts

Figure 23: RIIO opex allowance vs forecasts[26]



4.89. Both NGET and NGGT are forecasting lower expenditure than their allowances over the RIIO-T1 period. Expenditure in the early years of RIIO-T1 will be high due to the reorganisation changes before reducing in 2015-16 and remaining at this lower level until the end of the period.

4.90. SHE Transmission is forecasting a slight overspend against its allowance. This is due to opex costs associated with SWW projects which will be added in future years, but which have been included at present as capex.

4.91. SPT is also forecasting an overspend on RIIO-T1 opex allowances. The main reason for this is due to the change in accounting approach which will result in an increase of approximately £60m over the RIIO-T1 period. However, there should also be an equivalent fall in capex costs.

[26] Forecasts include actual data for 2013-14 year.

Transmission investment for renewable generation (TIRG)

4.92. Ofgem put the TIRG mechanism in place in 2004 to provide the Transmission Owners (TOs) with revenue allowances to connect renewable generation that was not forecast at the time the relevant transmission price controls were set. It includes explicit allowances and output obligations for specific projects for each of the TOs. Given the uncertainty around the design and cost of these projects, we provided flexibility in the mechanism for us to consider amending the revenue allowances up or down under defined circumstances. These include:

- TIRG income adjusting event (IAE) - an event or circumstance that has occurred or is expected to occur which has materially increased or decreased the forecast preconstruction and contingency costs for the relevant years. The TO must notify us and provide supporting evidence where it considers that an IAE has occurred.

- TIRG asset value adjusting event (AVAE) - where a relevant amendment to the scope of construction work is expected to cause additional costs or savings to be incurred. In order to vary their ex ante revenue allowances during the construction period through an AVAE, the TO is required to give notice of such an event to us as soon as is possible after it has occurred and in any event prior to the TIRG relevant year when construction of the project begins.

4.93. Most of the TIRG projects were completed in the previous price control (TPCR4) but there were two projects still to be completed in RIIO-T1 by SHE Transmission and SPT. These are the Beauly-Denny and South West Scotland projects.

4.94. The Beauly Denny upgrade of the existing 132kV transmission line to 400kV between Beauly in the north of Scotland and Denny in central Scotland is the largest project covered by the TIRG mechanism. SHE Transmission is responsible for delivering the majority of the project, while SPT is constructing the final 22km, which lie in its transmission area.

4.95. The South West Scotland project being delivered by SPT focuses on constructing power lines and an interconnector as part of developing the infrastructure for wind developments in south west Scotland.

4.96. In the first year of RIIO-T1 SHE Transmission spent £164m on Beauly-Denny projects. This takes its total expenditure to date on the project to £527m. The project is due to be completed in 2016, by which time SHE Transmission forecast it will have spent £709m. We have so far allowed £607m in funding for this project.

4.97. SPT spent £36m on the Beauly-Denny project in 2013-14 taking its total spend to date on the project to £70m. By 2016 SPT expects to have spent a total of £204m. SPT has received funding of £204m.

4.98. The total cost of the completed Beauly-Denny project is expected to be £913m, of which £597m (65%) has already been spent.

4.99. SPT has spent £19m in 2013-14 on the south west Scotland project. This takes the total expenditure to date to £26m. The project is due to be completed in 2016-17 by which time SPT expects to have spent £45m. SPTs has already received funding of £54m for the project.

5. Financial Performance

Chapter Summary

This chapter presents the opening and closing position of the regulatory asset value (RAV) for RIIO-T1 and the TOs return on regulatory equity (RoRE) performance. It evaluates the contribution of each main element of totex (ie opex and capex) to the total RoRE. It also identifies the key RoRE performance drivers.

Regulatory Asset Value

5.1. Regulatory Asset Value (RAV) is the value of capital investment in networks and reflects the cost of building the network assets that are used to transmit energy. The opening RAV balance for each TO for RIIO-T1 comprises the closing RAV balance from TPCR4, and the RAV additions represent the proportion of totex that we remunerate over the longer term. The relevant capitalisation rates for each TO were set at RIIO-T1 final proposals.

5.2. The price control allows licensees a return on RAV and return of money invested in the RAV, which comprises:

- Base revenue allowance which is the return to compensate the risk and opportunity cost borne by shareholders and debt holders who fund the capital investment (the weighted average cost of capital or 'WACC'). The WACC is designed to encourage licensees to enter into long-term financing arrangements needed for efficient investment in the network.

- An allowance to reflect depreciation of assets, which broadly reflects the annualised cost of maintaining assets. Depreciation allowances are deducted from the RAV.

5.3. Table 10 shows an increase in the opening RAV at the end of the price control year 2013-14. The closing RAV is calculated as:

opening RAV **plus** RAV additions (net of disposals) **less** RAV depreciation.

Table 10: RAV movement schedule for 2013-14 and forecast RAV[27] at the end of RIIO-T1 (excluding TIRG)

	NGET			SPT	SHE Transmission	NGGT			
Price base £m 2013/14 prices	TO	SO	Total	SPTL	SHET plc	TO	SO	Total	Total
Regulatory Asset Value (RAV)									
Opening RAV (before transfers)	10,140	87	10,226	1,276	795	4,684	62	4,745	17,043
Transfers	-	-	-	-	-	279	-	279	279
Opening RAV (after transfers)	10,140	87	10,226	1,276	795	4,962	62	5,024	17,322
RAV additions (after disposals)	1,156	42	1,198	239	98	263	26	289	1,825
Depreciation	(658)	(18)	(676)	(94)	(50)	(162)	(12)	(174)	(994)
Closing RAV	10,638	110	10,748	1,421	844	5,064	75	5,139	18,152
Forecast RAV at end of RIIO T1	13,967	137	14,104	2,700	2,883	5,987	97	6,084	25,772

5.4. Major capital infrastructure projects for electricity transmission networks e.g. Strategic Wider Works and connecting new sources of generation have been planned for the RIIO-T1 price control. As such, the trend of substantial increases in electricity transmission RAV values is expected to continue until after the end of the decade.

5.5. It should be noted that the closing value of Transmission Investment in Renewable Generation (TIRG) assets totalled £786m (SHE Transmission: £467m, SPT: £208m, NGET: £110m) as at 31 March 2014. These asset additions are partially reflected in the forecast RAV in Table 11 with the remainder in 'Shadow RAV[28]' until the projects reach completion.

5.6. At the end of RIIO-T1, the remaining 'shadow' RAV is forecast to be NGET: nil; SHE Transmission: £412m; SPTL: £131m.

5.7. NGGT had £367m of 'Shadow' RAV at 31 March 2014, which is all forecast to enter the main RAV before the end of RIIO-T1. This balance comprises investments funded through revenue drivers from previous price controls, which sit outside the core base revenue allowance for RIIO-T1.

Return on Regulatory Equity (RoRE)

5.8. We use RoRE analysis to estimate the financial benefits that are available across the network companies in RIIO-T1 from outperforming the price control assumptions. By the same token, RoRE analysis allows us to assess the financial penalties for underperforming the price control assumptions.

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[27] Forecast RAV is based upon the companies' latest published view of totex performance.

[28] Where investments are initially funded outside of the core RIIO-T1 price with a different allowed rate of return (WACC and depreciation) than set at Final Proposals the costs will be held outside of the main RAV in Shadow RAV. Once the normal allowed rate of return becomes applicable to the investments then the costs are transferred from Shadow RAV to the main RAV in the relevant year.

5.9. Regulatory equity represents the proportion of average annual RAV that is funded by shareholders (also known as 'Equity RAV'). This is based upon the notional gearing set at Final Proposals which results in equity proportions of 40% for NGET, 37.5% for NGGT and 45% for SHE Transmission and SPTL.

5.10. Returns represent the post-tax cost of equity set at RIIO-T1 final proposals plus revenue adjustments i.e. actual or forecast outperformance or underperformance compared with allowances set for each year at final proposals.

5.11. The return includes these adjustments:

- *Totex Incentive Mechanism* – The incentive strength represents the percentage that a licensee bears for overspending against allowances or retains for underspending against allowances.

- *IQI income reward/penalty* – A reward / penalty set at RIIO-T1 Final Proposals, which reflects the accuracy and quality of the business plans submitted by the licensee. These values remained fixed for the eight year price control period.

- *Output incentives* – Covering stakeholder satisfaction, network reliability, environmental performance and SO specific measures for both gas and electricity transmission.

5.12. It is important to note that the RoRE we have calculated for each licensee at the end of 2013-14 is an estimate of the average annual return[29] that shareholders could expect over the eight year price control period. It incorporates actual totex incurred in the year plus the seven year forecast for 2014-15 to 2020-21. This data is consistent with the latest expenditure figures published in the Transmission companies annual reports, published in September 2014.

5.13. We have not calculated a separate RoRE for 2013-14 as this figure would be skewed by the impact of capex phasing whereby an underspend/overspend in 2013-14 may be caught up in future years of RIIO-T1 allowing the overall expected totex profile to be maintained.

5.14. The totex forecast assumes that all related outputs will be delivered within the eight year price control period.

[29] Arithmetic Mean

5.15. The eight year RoRE calculation does not incorporate forecast output incentive performance for 2014-15 to 2020-21 as licensees currently do not have a reliable way to work out these figures.

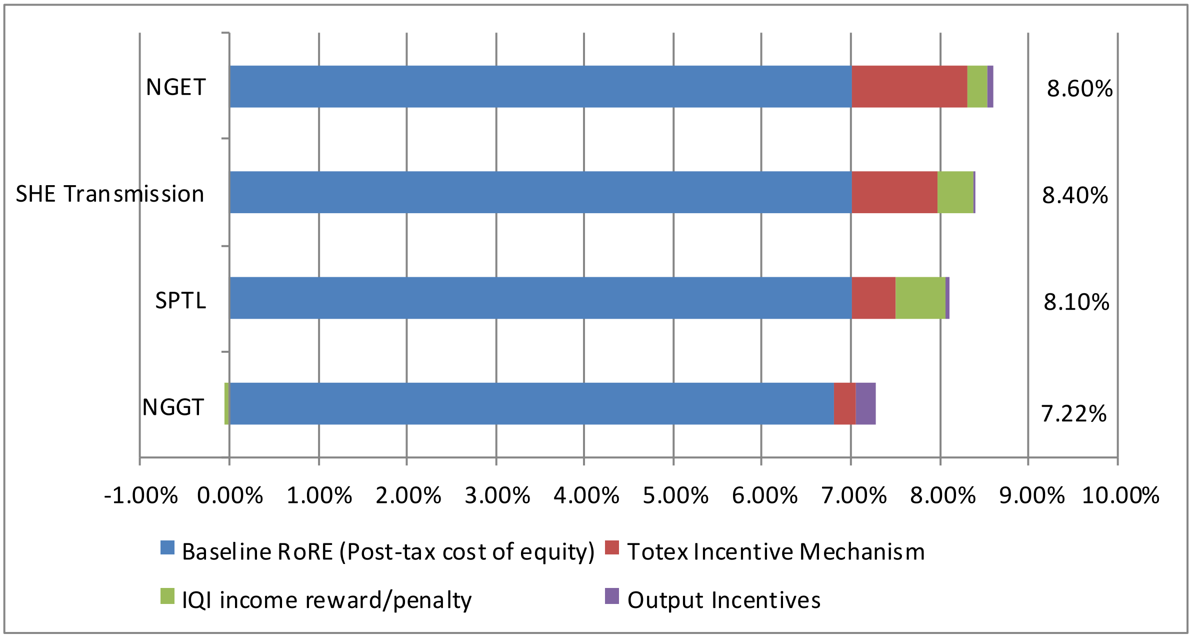
5.16. Transmission Investment in Renewable Generation (TIRG) has also been excluded from the RoRE calculation both in terms of the Shadow RAV associated with TIRG projects. This sits outside the main RAV subject to the price control until projects are completed and the incentive performance attributable to TIRG. A future methodology for the treatment of TIRG is still being reviewed.

5.17. Table 11 and Figure 24 shows the composition of the eight year average RoRE for each of the TOs:

Table 11: Transmission Operators' eight year RoRE forecast

	8 year RoRE	Baseline RoRE (Post-tax cost of equity)	Totex Incentive Mechanism	IQI income reward/penalty	Output Incentives
	Total				
NGET	**8.60%**	7.00%	1.30%	0.23%	0.07%
SHE Transmission	**8.40%**	7.00%	0.98%	0.40%	0.02%
SPTL	**8.10%**	7.00%	0.50%	0.57%	0.03%
NGGT	**7.22%**	6.80%	0.26%	-0.06%	0.22%

Figure 24: Eight year RoRE forecast for RIIO T1



5.18. The impact of forecast SO totex performance and 2013-14 incentives (market balancing incentives) included in the eight year RoRE calculations in Table 11 and Figure 24 is 0.06% for NGET and 0.14% for NGGT.

Appendices

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Appendix 1 – System Operator Performance

Electricity SO incentive performance

1.1. National Grid Electricity Transmission (NGET) is the system operator (SO) in GB and is responsible for balancing the electricity system to ensure generation and demand are balanced on a continuous basis. To do this NGET buys and sells electricity and procures associated services. The cost NGET incurs is recovered from users of the system via Balancing Services Use of System (BSUoS) charges. NGET also provide information, such as wind forecasts, to aid market participants in their actions.

1.2. One of Ofgem's roles as the GB Electricity regulator is to ensure that NGET develop and maintain an economic, efficient and coordinated system of electricity transmission. To help achieve this Ofgem has set financial and reputational incentives which encourage NGET to meet these outcomes. These SO incentives are outside the RIIO-T1 price control mechanism.

1.3. The current SO Electricity Incentive scheme includes:

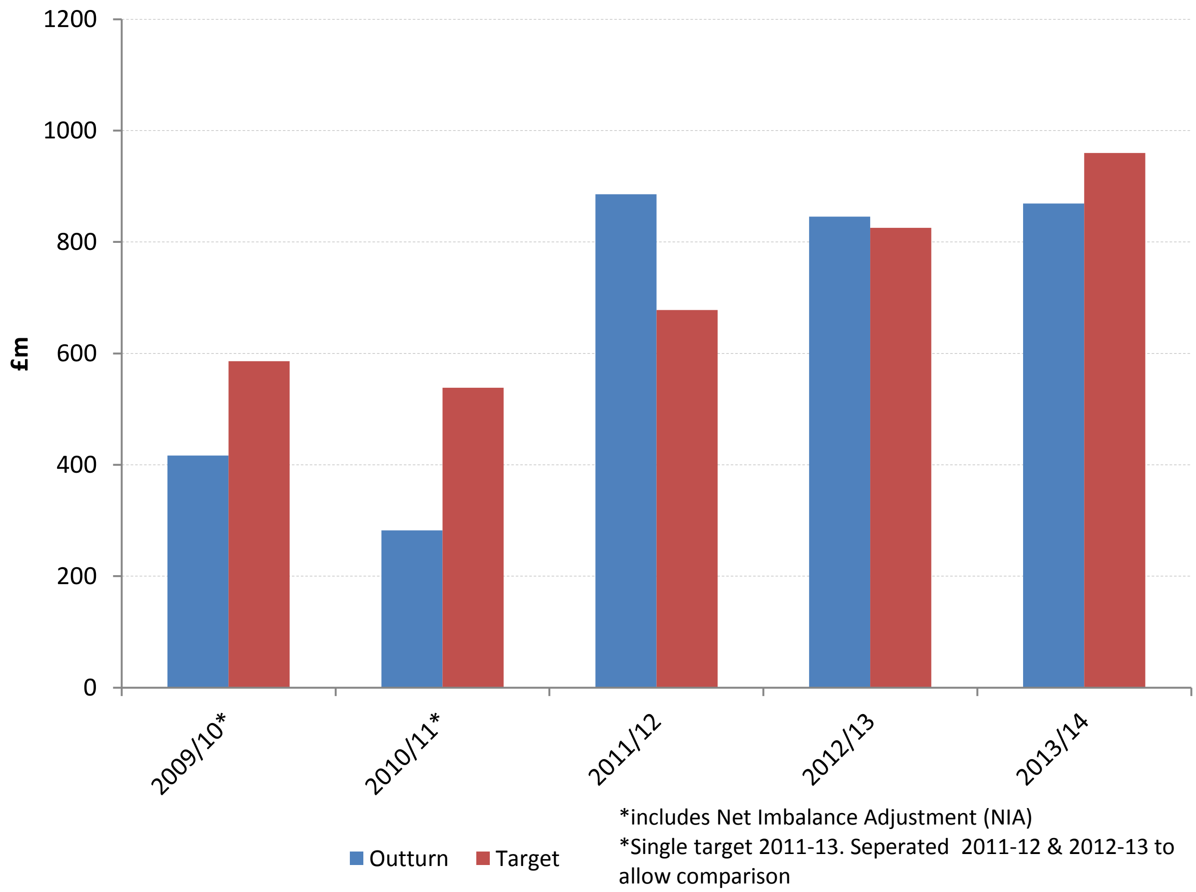
- Minimising balancing costs on the transmission network (Balancing Services Incentive Scheme (BSIS))
- Wind Forecasting Incentive
- Increased Transparency
- System Operator Innovation Roll-Out Mechanism

1.4. The main incentive on the SO is the Balancing Services Incentive Scheme (BSIS). BSIS incentivises NGET on the actions it has to take in order to operate the GB Electricity Transmission System. Under the BSIS balancing cost targets are agreed, with NGET receiving 25 percent of any savings against the target and incurring 25 percent of any cost above the target, subject to a cap and floor of ± £25m. Included is a target for the costs incurred in ensuring that the system is kept in balance, either to balance energy or to manage constraints. BSIS also incentivises NGET on the costs of ensuring that they are able to respond to an event that would require them to re-energise part of the transmission system if needed, known as Black Start.

1.5. Up until 2010-11 the scheme was set on an annual basis but now it is set for two years with the current scheme running from 2013-15. Since 2011 the incentive schemes have been based on a combination of forecast and actual data inputs over a two year period, where the target is estimated by pre-agreed models.

1.6. Figure A1 shows actual expenditure against target costs up to the current scheme period. Under the incentive scheme NGET retains a percentage of any underspend against the target (subject to a cap) and is liable for a percentage of any overspend (subject to a scheme floor).

Figure A1: Electricity out-turn costs against target costs from 2009 to 2014 (balancing activity)



1.7. Under the BSIS the target is set using two models. One model sets the target for constraints management costs and the other derives a target for NGET's energy balancing actions. A rigorous monitoring framework is in place, with NGET providing performance data to Ofgem to ensure incentives are being delivered on and to verify the targets remain robust.

1.8. Under the Electricity licence NGET has a condition requiring it to make improvements to the models. These models have improved in sophistication and accuracy over the last four years, which has increased confidence that they could deliver robust targets. Since 2012-13 NGET have been within range (see figure 1), even though this period has been technically challenging, which is in part down to improvements in these models.

Gas SO incentive performance

1.9. National Grid Gas Plc (NGGT) is the gas System Operator (SO) for GB and is responsible for balancing the system across Great Britain (GB) as well as playing a key role in providing information to market participants, such as demand forecasting. Under the Gas licence the SO is required to manage the system in an economic and efficient manner.

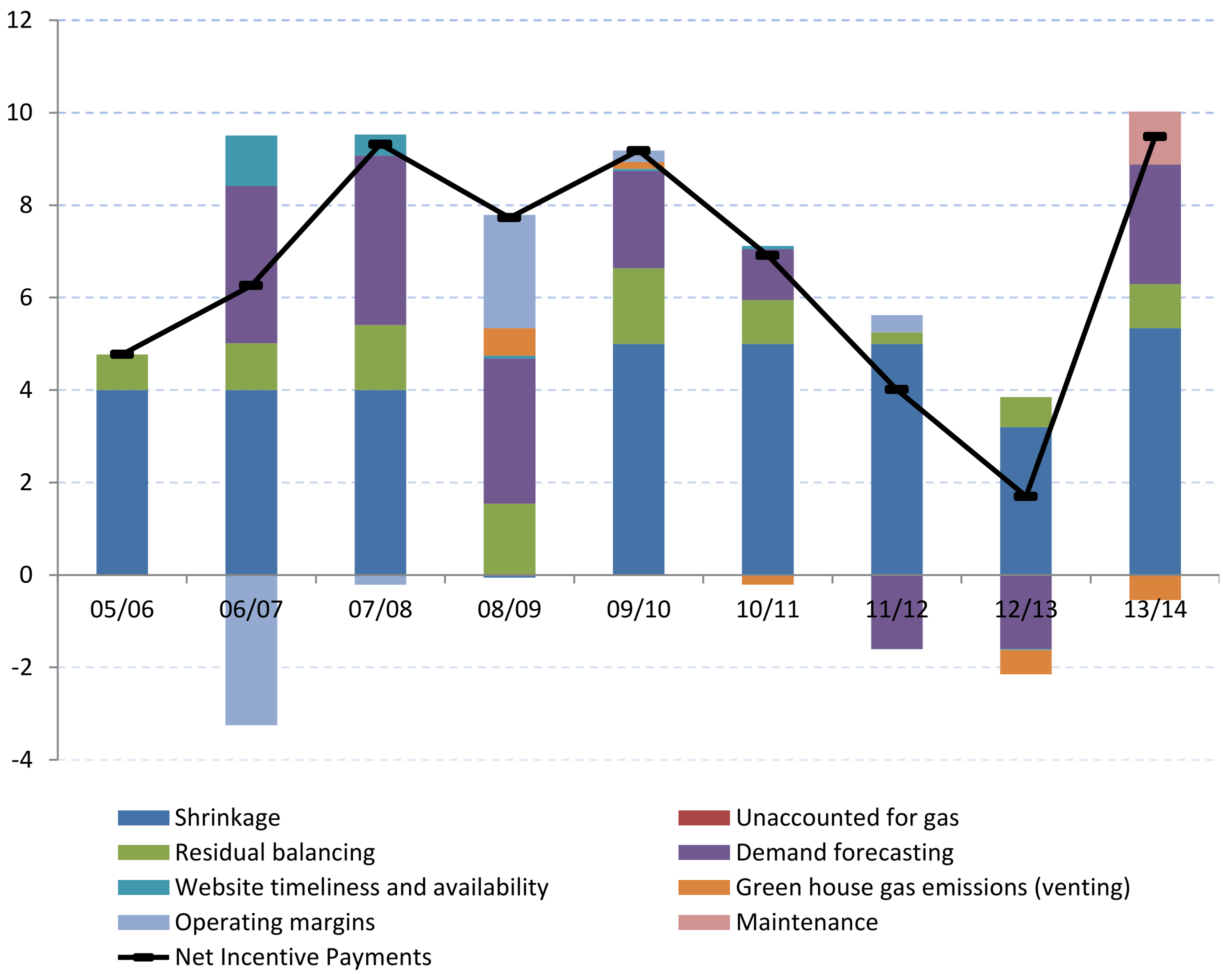
1.10. The Gas SO incentive scheme is designed to motivate NGGT to reduce the costs of operating the network and to promote innovation in the way the system is run. A new incentive package was introduced on 1 April 2013 with most of the incentives being set for an eight year period to align with the RIIO-T1 price control. We also introduced new incentives or made significant changes to existing incentives and as such these were set for a shorter period to assess their effectiveness before implementing them for a longer period. The new package maintains relevant aspects of previous incentives as well as introducing some new components.

1.11. The current incentives are as follows:

- Demand Forecasting
- Residual Balancing
- Shrinkage
- Greenhouse Gas Emissions
- Maintenance
- Unaccounted for Gas (UAG)
- Operating Margins

1.12. The first five of the above incentives are financial, with NGGT rewarded or penalised for over or underperformance against a target. The UAG and Operating Margins incentives are reputation-based incentives without financial implications, due to being license requirements.

Figure A2: Summary of the performance of NGGT SO from 2005-6 to -2013-14

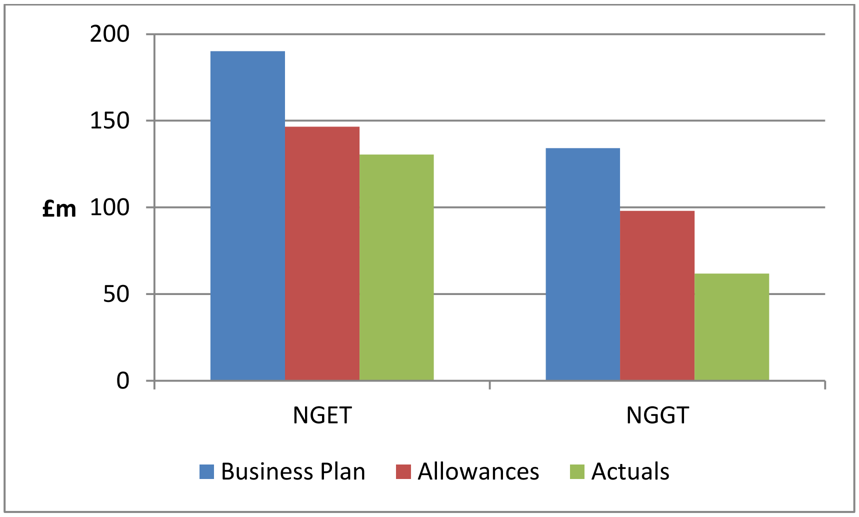


1.13. In the last eight years, NGGT has outperformed the incentives each year, receiving incentive payments ranging from less than £1.7m in 2012-13 to 9.15m in -2013-14.

SO internal costs

1.14. The SO internal costs, made up of IT and staff costs, enables NGET and NGGT to undertake the SO balancing activities described above. In the RIIO-T1 period both NGET and NGGT have been granted totex allowances. We discuss below the performance in 2013-14 and the forecast for RIIO-T1.

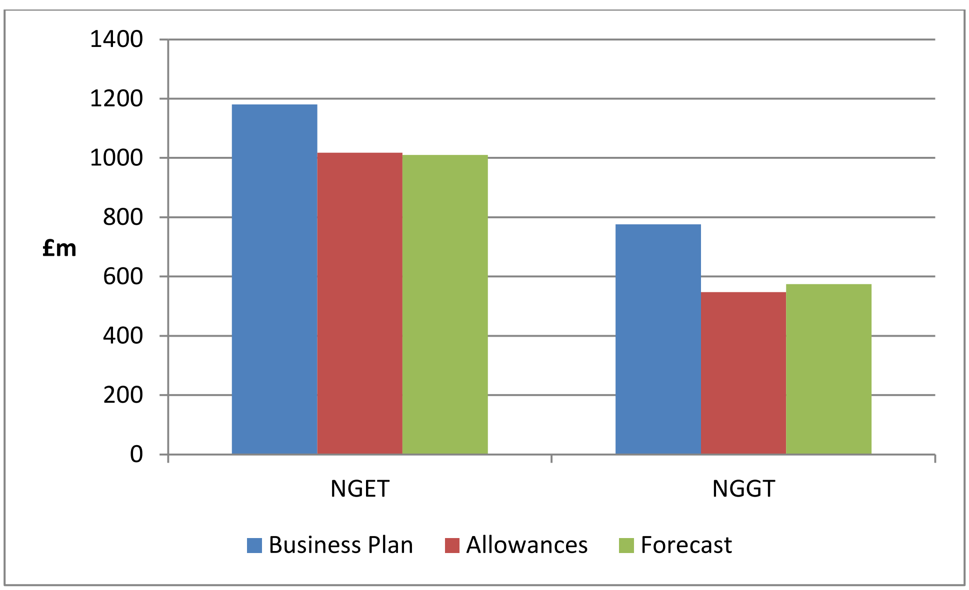
Figure A3: Actual SO internal totex for 2013-14



1.15. In the first year of RIIO-T1 both NGET and NGGT have underspent the allowances, NGGT by 37%. In both cases this was due to underspends on capex. Capex underspending was due to delaying spending on IT systems until future years.

1.16. Figure A4 below shows NGET and NGGT’s Totex forecast for the whole of the RIIO-T1 period. Despite underspending in the first year both NGET and NGGT are expecting to spend close to their totex allowances over the 8 year period. We will monitor progress over future years.

Figure A4: Forecasted SO internal totex for RIIO-T1



Appendix 2 – Customer Bill Impact Methodology

2.1 We have used the average electricity and gas transmission network charges per household as per the TPCR4 close out report re-based from 2012-13 prices (Electricity: £21.24 Gas: £16.22) to 2013-14 prices (Electricity: £21.78 Gas: £16.63) using the average ONS RPI between April 2013 and March 2014 as a starting point.

2.2 The network transmission charges reported in the TPCR4 close out report represented 4% of the average household electricity bill (£534 inc. VAT) and 2% of the average household gas bill (£811 inc. VAT) at the end of December 2012. This information was correct as per Ofgem Factsheet 98 published in February 2013.

2.3 We calculate the movement in each component of 2013-14 actual revenue (as set out in Figures 1 and 2) against re-based 2012-13 actual revenue based upon information from the TOs' Revenue RRPs submitted to Ofgem in July 2014.

2.4 The movements are calculated as a percentage of re-based 2012-13 actual revenue and are applied to the re-based average transmission network charge to compute the 2013/14 bill impact of each component. Therefore the effect of inflation has not been reflected in the bill impact.

1.17. The 2013/14 bill impact calculation assumes that 100% of the increase in TOs' actual revenues is passed on to the average household electricity and gas bills. In actuality increases in network charges are split between generators and suppliers who may decide the proportion to pass on to the consumer.